BEFORE THE
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
UNITED STATES DEPARTMENT OF TRANSPORTATION
WASHINGTON, D.C.

Notice of Proposed Rulemaking	)	Docket No. PHMSA-RSPA-2004-19854
Pipeline Safety:	)	RIN: 2137-AE2137
Integrity Management Program for	)	
Gas Distribution	)	
	)	

COMMENTS OF THE AMERICAN GAS ASSOCIATION ON THE PROPOSED RULE FOR NATURAL GAS DISTRIBUTION INTEGRITY MANAGEMENT

The American Gas Association (AGA), founded in 1918, represents 202 local energy companies that deliver natural gas throughout the United States. There are nearly 70 million residential, commercial and industrial natural gas customers in the U.S., of which 92 percent — more than 64 million customers — receive their gas from AGA members. AGA is an advocate for natural gas utility companies and their customers, and provides a broad range of programs and services for member natural gas pipelines, marketers, gatherers, international natural gas companies and industry associates. Today, natural gas meets almost one-fourth of the United States' energy needs.

I. GENERAL COMMENTS

AGA commends the Pipeline and Hazardous Materials Safety Administration (PHMSA) on its use of a collaborative process in the Distribution Integrity Management Program (DIMP) Phase 1 report, which formed the basis for much of this proposed rule. The stakeholders in the DIMP Phase 1 report included federal and state regulators, public representatives, emergency response personnel, operators, and consultants. AGA supported the recommendations of the DIMP Phase 1 report and is pleased to see PHMSA incorporate many of the recommendations into the proposed rule.

In general, AGA has determined that the DIMP rule is well written and should be adopted. However, AGA is concerned that PHMSA deviated from some of the recommendations of the DIMP Phase 1 report. These deviations have created sections in the proposed rule that AGA believes are inconsistent with the regulatory structure that is needed at the state level for pipeline safety. AGA notes these deviations and provides recommended changes in Section II where specific comments are provided.

AGA also notes that the energy picture in the United States and throughout the world has changed drastically since the beginning of the development of the gas distribution integrity management rule. Over the last 2-3 years, the price of oil has risen from approximately $40 per barrel to $145 per barrel and natural gas has risen from $3 per MM Btu to $13 per MM Btu. While these prices have begun to drop from their record highs, consumers of natural gas have already been adversely impacted by the price increases. Increasing numbers of residential customers have had their services terminated because of inability to pay. Alternatives to home heating, such as space heaters, are less safe than natural gas and cause more injuries and fatalities.

Based on recent increased energy costs, AGA believes that state Public Utility Commissions (PUCs) cannot support an integrity management rule that places additional cost increases on consumers without a demonstrated benefit to improve safety. There are specific areas of the proposed rule that will help to improve safety and are consistent with safety measures in place at the state level. AGA notes in its comments a few sections of the rule that it believes create unnecessary burdens and costs without yielding associated safety benefits.

The summary discusses four major areas of the rulemaking. These areas are: (1) avoid excessive record keeping requirements; (2) the need to modify the Plastic Pipe Database Committee (PPDC); (3) inability of operators to implement vague and unenforceable human factor requirements in integrity management programs; and (4) the need to efficiently implement alternative inspection intervals. AGA provides detailed comments on these and other issues later in this letter. AGA submits Appendix A herein with suggested language for 49 CFR 192 Subpart P.

Documentation for Gas Distribution Integrity Management Plans

The AGA commends PHMSA for generally following the recommendation of the DIMP phase 1 report when it developed a framework for distribution integrity management in sections 192.1007 and 192.1015. PHMSA did an excellent job of bringing all stakeholders together in the DIMP phase 1 collaborative process. The primary concern that AGA has with sections 192.1007 and 192.1015 is that PHMSA deviates from the recommendations of the DIMP phase 1 report in that the proposed rule appears to require unnecessary and excessive documentation within an operator's distribution integrity management plan. The regulation's requirement that operators document all of the decisions they make in implementing distribution integrity management is not practical. Gas distribution systems are so intricate that it would require an enormous paperwork burden to document all the decisions associated with providing service to millions of customers.

Plastic Pipe Data Collection and Analysis

Plastic pipe used in natural gas distribution service has proven to be safe and reliable. The amount of plastic piping used in natural gas service has increased from 9,200 miles in 1965 to 544,300 miles in 2007. Plastic pipe has supplanted steel pipe as the material of choice for gas distribution because of its superior properties.

Even with plastic pipe's proven performance for safety and reliability, AGA believes that it is reasonable for PHMSA to be concerned with the performance of plastic pipe. The record of selective brittle pipe failures in the early history of plastic pipe should keep operators and regulators prudent in the selection and use of materials. AGA notes that the existing Plastic Pipe Database Committee (PPDC) has done an excellent job in tracking the trends in plastic material performance and believes that eliminating this committee and creating a completely new plastic pipe database is unnecessary and counterproductive. The PPDC is comprised of federal and state regulators, gas distribution operators, plastic pipe manufacturers, the American Public Gas Association, and the National Transportation Safety Board (NTSB). AGA staff is the administrator of the database and is not a voting member of the PPDC. As administrator, AGA has no say in the operation of the PPDC and follows the instruction of PHMSA and the other PPDC members. AGA has included the written consensus, charter and mission of the

PPDC as Appendix B. AGA has also included recent reports from the PPDC in Appendix C.

The proposed rule states, "*PPDC information has limited distribution and is generally not available to operators who do not participate in the program.*" This is incorrect. The PPDC has created a public website that includes the PPDC annual reports, along with manufacturers' information, a plastic pipe timeline, PPDC presentations and other relevant information. Each PPDC annual report contains a full listing of "suspect" material, as identified by the committee, and all PPDC representatives are encouraged to communicate the findings of the PPDC to the stakeholders they represent and to others.

AGA believes there are some fundamental problems in attempting to establish a new plastic pipe database. The proposed rule does not discuss if provisions will be established for database quality control and quality assurance (QA/QC); if a committee will be established to oversee the database operation and maintenance; if there will be involvement of plastic pipe manufacturers or subject matter experts; or any of the other features that made the existing PPDC successful. AGA believes the proposed rule's language would eliminate the existing PPDC, because there would be no need for two systems, and replace it with a database that, as proposed, would provide little or no safety benefit. The PPDC works because all stakeholders are involved.

AGA presents some options to modify how the PPDC operates and the information that it releases. Modifying the PPDC in a 90 day comment period is not an easy task. The PPDC normally meets every six months and modifying the charter and procedures used by the PPDC requires approval of all the volunteer entities. Therefore, continued discussion after the close of the DIMP comment period may be needed to evaluate and implement changes to the PPDC. These discussions are <u>not</u> to be considered a part of the rulemaking process, because the PPDC is an existing entity separate from the proposed rule.

AGA was invited as an observer to the August 26 – 27, 2008 PPDC meeting. AGA discussed the DIMP NPRM and provided copies of presentations from the AGA DIMP Workshop (held August 13 in Chicago) regarding the proposed rule's plastic pipe database. (The presentations are in the PHMSA docket). AGA believes that the PPDC will submit comments that support the continued utilization of this committee.

Prevention Through People

The proposed distribution integrity management program regulations include requirements for operators to understand the threats affecting the integrity of their systems and to implement appropriate actions to mitigate risks associated with these threats. These include a first step towards instituting a ‘‘Prevention Through People’’ (PTP) program to address human impacts on pipeline system integrity. Human impacts include both errors contributing to events and intervention to prevent or mitigate events. As part of considering the threat of inappropriate operation (*i.e.,* inappropriate actions by people), this proposed rule would require operators to evaluate the potential for human error.

Seeking to reduce incidents by minimizing human error is commendable. However, the AGA has some fundamental problems with the PTP concept in the proposed rule. A major problem is that the concept as presented in the rule is too vague to be an enforceable regulation.

Alternative Inspection Intervals

AGA supports the concept of alternative inspection intervals. When the pipeline safety code was adopted in the early 1970s it was reasonable and prudent to adopt a consistent set of federal pipeline safety standards for the entire nation. Now, in the 21st century, data analysis can distinguish the effectiveness of pipeline safety inspections. Operators and regulators can use this analysis to tailor their regulations to meet the needs of the local stakeholders.

The underlying purpose of PHMSA’s integrity management requirements is to improve knowledge of the condition of each operator’s pipeline and to use that information to identify new risk control solutions and to better focus risk reduction efforts. Resources would be better allocated to higher risk threats. Furthermore, AGA does not believe the DIMP regulation would be cost beneficial unless an effective method to implement alternative inspection intervals is included in a final rule.

AGA agrees with PHMSA's conclusion, "*that implementing integrity management for distribution pipelines should offer additional opportunities to improve efficiency in assuring safety. Improving efficiency in assuring safety requires, however, that it be possible to reduce efforts that have marginal effect on controlling risk in order to shift resources to more effective actions.*"

As part of a continuing effort to improve efficiency and to make the approach to pipeline safety more risk-based, PHMSA is proposing an approach that would allow operators and the States to have more of a role in setting compliance intervals for distribution operators within a state. Rather than continuing to require distribution operators to comply with intervals set by existing federal regulation in Part 192, this approach would let an operator use its distribution integrity plan, and the risk assessment on which it is based, to propose alternative intervals for Part 192 requirements that they must now implement periodically. Operators could propose extended intervals for threats and areas (e.g., portions of pipeline systems) where risk is low, making the application of these requirements more risk-based.

Regulatory Evaluation

AGA has reviewed the preliminary regulatory impact analysis that PHMSA has submitted into the docket dated June 17, 2008. AGA agrees with most of the information in the analysis, but makes the observations below.

AGA disagrees with the regulatory evaluation discussion and conclusion that the gas distribution system that serves local markets does not fit a competitive market model. The Public Utility Commissions that have primary jurisdiction over gas distribution operations are responsible for the safety and operating functioning of gas distribution within a competitive market. Public utility commissioners, public representatives, and operators engage in constant discussions about the resources necessary for pipeline safety and the rates that the public should be charged for natural gas delivery. State public utility commissions are chartered to manage safety, rates, and all market forces that affect gas distribution.

AGA believes that it is a noble goal to decrease incidents and reported serious injuries by 50%, but AGA does not see facts within the regulatory analysis to support these assumptions.

AGA believes reducing lost gas is important, however the DIMP phase 1 report explained the difficulty in analyzing lost gas. AGA does not see data in the regulatory analysis that supports PHMSA conclusions regarding the amount of lost gas reductions.

PHMSA Guidance Document

AGA reviewed the PHMSA DIMP Guidance document published in the docket. The guidance document developed by the Gas Piping Technology Committee is more thorough than the PHMSA document. That is to be expected because the GPTC document was developed with the support of many stakeholders. PHMSA was very supportive of the GPTC guidance effort. AGA believes that the PHMSA guidance document is not necessary for operators to effectively implement DIMP. The GPTC document will be available as a separate appendix to the GPTC Guide. The cost will be minimal in absolute terms and compared to the benefits provided. Additionally, there is the potential for adverse consequence of conflicting guidance if PHMSA supports multiple guidance documents.

II. SPECIFIC COMMENTS

AGA provides specific comments on the proposed rule in the sequence presented in the federal register notice.

§ 192.1001 What do the regulations in this subpart cover?

AGA agrees it is important to highlight the operating and structural differences between gas distribution operators, master meter operators, and LPG operators. PHMSA has a statutory obligation to evaluate integrity management regulations for each of these entities.[1] The DIMP Phase 1 report suggested that all three entities be regulated in integrity management. The operative question here is, “what level of regulation is proper for master meter operators and LPG?” AGA notes that liquid petroleum gas is denser than air and therefore does not have the safe dispersion properties of the less dense-than-air natural gas. We see no provisions in the proposed rule to address this higher level safety threat. AGA has minimal experience with LPG operations, and therefore will

[1] Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006

not provide a detailed analysis regarding what is prudent for integrity management of those facilities.

§ 192.1003 What definitions apply to this subpart?

There are two issues regarding the proposed definition for damages. AGA has concerns about the definition provided for damages because there may be confusion about reporting damages that involve or do not involve excavation. Also, it is a significant change to attempt to report distribution piping damages that do not involve leaks. Some operators have explained that the expanded reporting of damages that occur, even if a leak is not present, creates recordkeeping problems.

It should be noted that neither the proposed definition nor revisions proposed by AGA will change how operators safely maintain their pipelines. The definition for damages is for data collection and reporting purposes. It does not control and will not impact pipeline maintenance. Pipeline operators will follow the pipeline safety code or possibly their own more stringent procedures to prudently repair pipelines, whether excavation damages or gas leakage is involved.

The existing annual report documents leaks, but not damages. The proposed rule requires reporting excavation damages, but not other damages. PHMSA may want to define “excavation damage” to distinguish it from other damages to support reporting requirements. For example, would damage to anodes or test wires be considered “damages” and does PHMSA want this reported? AGA suggests that the Notice of Proposed Rulemaking (NPRM) definition be modified to:

“Excavation Damage means any impact or exposure resulting in the immediate release of gas from ~~repair or replacement of an underground facility, related appurtenance, or materials~~ ~~supporting~~ the pipeline.”

AGA recommends that “Excavation Damage” remain the only definition in the subsection. PHMSA may receive requests for additional definitions to be added to the subsection. Stakeholders often prefer the certainty provided by definitions. However, historically, definitions added to the pipeline safety code remain the same for decades. Therefore, care must be taken before adding definitions, because definitions are difficult to change once they are codified.

Definitions for hazardous leak, excavation ticket and plastic pipe failure may be proposed to promote consistency in reporting. These definitions should be considered for reporting forms, not section 192.1003. If the definitions on report forms promote consistency, then no changes are necessary. If PHMSA determines that the definitions create reporting problems, they can be changed by following the simple requirements of the Paperwork Reduction Act, rather than amending the DIMP regulations. Possible definitions for the reporting forms include:

Hazardous leak means a leak that represents an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous.

Excavation ticket means the receipt of information by the underground facility operator from the notification center regarding onsite meetings, project design or a planned excavation.

Plastic pipe failure means plastic material failures of in-service pipe, fittings or joints (this includes installation errors that fail after the pipe is put in service). This does not include excavation damage. This does not include failures of piping before the piping is put into service but does include failures of any kind of plastic piping material. These are failures where the plastic pipe, fitting, or joint has experienced failure through the wall, body or shell of the plastic component.

§ 192.1005 What must a gas distribution operator (other than a master meter or LPG operator) do to implement this subpart?

Some clarification is needed regarding what is meant by "fully implement" an integrity management program within 18 months after the final rule. The language could be interpreted to mean that an operator would have to implement all the elements in an integrity management program in all parts of its distribution system within 18 months. This is not practical. As an example, Congress gave operators of gas transmission pipelines 10 years to fully implement their integrity management program for approximately 300,000 miles of transmission pipelines. Gas distribution operators have more than 2,000,000 miles of piping. Gas distribution integrity management cannot be fully implemented in 18 months.

AGA makes several recommendations for the implementation requirements of this subsection. The implementation deadline should be extended to 24 months. Many operators, especially medium and large operators, will have to change their computer databases to collect and analyze data necessary to implement the proposed distribution integrity management program. It will take several months for information technology staffs to assess changes with the operating staffs, make the program changes, and evaluate the reliability of new databases.

The final rule should clarify that 49 CFR 192.1007 does not require that integrity management plans for all portions of an operator's distribution system must be implemented within the proposed 24 month deadline. The intent should be to:

- Complete the written distribution integrity management plan,
- Document a demonstrated knowledge of the distribution system,
- Begin to identify the threats associated with the distribution system,
- Begin to evaluate and rank the risks associated with the identified threats, and
- Begin implementing measures to address the risks.

AGA is also concerned that section 192.1005(b) can be construed to require operators to develop elaborate integrity management algorithms to satisfy the "processes" requirement of the subpart. AGA believes the term processes can be deleted without adversely affecting the intent of the proposed rule. The proposed subsection would read:

> (b) *Procedures.* An operator's program must have written procedures ~~describing the processes~~ for developing, implementing and periodically improving each of the required elements.

The DIMP Phase 1 report stated that,

> *"There are no major areas of 49 CFR 192 that need to be changed to address distribution integrity management, with the exception of a high-level, risk-based, flexible performance regulation to require a written distribution integrity management plan by the operator, although some incidental revisions may be needed to avoid duplication or conflict. The requirement should be for a broad framework of risk-based actions to address those areas where the risk to public safety is the highest."*

Since there are no major technical areas that need to be created for Distribution Integrity Management, there is no need for new elaborate processes. The subsection should direct operators to write procedures that will use the pipeline safety code to satisfy the seven elements in 192.1007.

§ 192.1007 What are the required integrity management (IM) program elements?

In general, AGA is supportive of the seven primary elements required in an operator's DIMP Plan. However, AGA has significant concerns relating to the proposed requirement for a section titled "Assuring Individual Performance", as noted under 192.1007(d), and the preceding language in 192.1007(b) stating *"… the operator must evaluate the contribution of human error to risk and the potential role of people in preventing and mitigating the impact of events contributing to risk.*" In its discussions with operators and regulators, AGA has concluded people are confused by this proposed requirement.

The concept of Prevention Through People (PTP) has been promoted previously by PHMSA, but it has been raised within the arena of control room management. It is important to note that human factors was cited by Congress in the 2006 PIPES Act, but only in relation to Control Room Management. There is no congressional mandate for PHMSA to require operators to specifically address human factors under the DIMP regulation. AGA believes human factors are already covered under existing regulations.

AGA believes this concept may have some merit, but it must be considered in a separate forum apart from Distribution Integrity Management. Trying to incorporate it in DIMP causes confusion and diminishes the focus which should be placed upon the core issues within DIMP - - data integration, risk assessment, threat mitigation, and program evaluation. After the final rule is issued for DIMP, AGA suggests a government-industry task group be formed to fully investigate what additional provisions might be warranted under this concept of "Prevention through People." The task group could perform a review of the pipeline safety code and determine if there are any human behavior gaps, which should be addressed through new or enhanced regulations, or other activities.

AGA presents four points which support its position on this particular issue.

1. **Existing programs sufficiently address the threat of inappropriate actions of individuals**

Distribution operators are already implementing programs which address the behaviors and actions of employees, contractors, 3rd party excavators and the public. Operator Qualification (OQ) was codified in 1999 and operators are qualifying employees on various tasks that have the potential of affecting the integrity of the pipeline. Drug and alcohol testing is mandatory and is performed for operator employees and contractors. Operators are already required under 192.614 to develop a comprehensive damage prevention program. In addition, the NPRM for DIMP suggests an operator should consider enhancements to be made to its damage prevention program. Under 192.616, operators have had public education programs implemented since 2006.

AGA does not understand what additional types of risk management measures PHMSA is seeking for operators to implement under 192.1007(d).

2. **The proposal is vague and would be too subjective to enforce fairly**
   While AGA favors the performance-based approach embodied by the DIMP NPRM, the provision in 192.1007(d) stating *"…operators must list risk management measures to evaluate and manage the contribution of human error and intervention to risk… and implement measures appropriate to address the risk*" is too ambiguous and esoteric for operators as well as regulators who must enforce the regulation. AGA understands PHMSA is interested in grouping the threats into three general categories: i) System-related; ii) Process-related; and iii) Human factors. However, AGA encourages PHMSA to continue using the eight threats that industry has been using for years to account for the fundamental causes of incidents to distribution pipelines. In performing a risk assessment, operators can determine if inappropriate actions by people are pertinent and if so, what additional measures may be warranted. For example, there is no human element for the threat of natural force damage, but there is one for the threat of excavation damage.

3. **No basis for fatigue management policies**

   AGA acknowledges that the proposed rule on Control Room Management has a requirement for operators to address fatigue management for their controllers. This is a requirement of the Pipeline Safety Act of 2006. However, there is no data or information that would suggest such a provision for other employees would enhance the integrity of distribution systems.

4. **PTP not included anywhere in DIMP Phase 1 Report**

   As PHMSA knows, a significant amount of energy and time was put into the creation of the DIMP Phase 1 Report. Several experts from the federal government, industry, state representatives and the stakeholder public participated in the development of this document which served as the basis for the NPRM. The seven elements of a DIMP Plan are pulled directly from the DIMP Phase 1 Report. Yet, nowhere in this report is there mention of a need for operators to account for the threat of inappropriate human behavior with the creation of a procedure titled "Assuring Individual Performance." AGA is not clear why PHMSA feels compelled to add this particular requirement under DIMP. The proposed rule preamble states that PHMSA asked the GPTC to develop guidance for the rule. The GPTC did an excellent job of developing guidance for the DIMP framework that was presented in the DIMP Phase 1 report. However, the Prevention Through People concept was not in the DIMP Phase 1 report and therefore no guidance is available.

Again, AGA believes the PTP concept may have merit, but it is unreasonable for PHMSA to impose it though the DIMP regulation. Administratively, it may be more appropriate for PHMSA to work with states and operators to first determine where human factors gaps may exist in the code before addressing new human factors.

§ 192.1009 What must an operator report when plastic pipe fails?

AGA must first say that it has a high degree of confidence in the plastic pipe infrastructure of the United States natural gas distribution system. AGA agrees with comments of state regulators who participated in the AGA Chicago DIMP Workshop, that there is no apparent problem that warrants a mandatory national plastic pipe database.

AGA believes the proposed requirements to collect and report plastic pipe data would be unnecessary in a final rule for distribution integrity management. Modifications to the existing Plastic Pipe Database Committee (PPDC) can enhance the understanding operators have about the safety performance of plastic pipe; avoid creating a new database system; and avoid terminating the successful work produced by the PPDC. AGA comments refer to the proposed rule's database as the Mandatory Plastic Pipe Data Reporting System (MPPDRS). AGA believes the Mandatory Plastic Pipe Data Reporting System presented in the proposed rule has deficiencies and will not enhance safety or the understanding of the performance of plastic pipe.

AGA provides herein an explanation of the scope and performance of the PPDC. AGA shows the differences in the Mandatory Plastic Pipe Reporting system that is proposed and existing PPDC. AGA also provides answers to questions PHMSA presented in the proposed rule regarding plastic pipe data collection.

PHMSA's objectives for creating a mandatory plastic pipe database system or modifying the PPDC are not completely clear to AGA. The preamble states:

> *PHMSA believes changes to the PPDC process could significantly improve operator insight into the risks associated with plastic distribution pipelines. In particular, more data of better quality and improved availability of results from PPDC data analysis could help inform operators of potential integrity issues related to their plastic pipe.*[2]

> *The proposed requirements to collect and report data on plastic pipe failures from the final rule may not be necessary if another group agrees to perform these functions. PHMSA invites comments on the appropriateness of the proposed reporting requirements.*[3]

The PPDC was created to address safety concerns presented in the National Transportation Safety Board report on brittle pipe failures. AGA believes the PPDC has been successful in improving the understanding of the performance of plastic pipe and

[2] Federal register at 36026
[3] Id

has helped enhance the industry's safety record. The PPDC currently makes publically available a listing of suspect plastic materials, manufacturers' information and other relevant data. This information is available to all, including operators that do not participate in the PPDC, state and federal regulatory agencies, manufacturers and the public.

The PPDC can improve the way in which it communicates with operators and other stakeholders. However, improvements in communication are better accomplished by the members of the PPDC team, rather than by attempting to modify the database itself. These members include NTSB, PHMSA, plastic pipe manufacturers and operators. Trade associations also have a role in improving communication regarding plastic pipe performance. Creating a new database, whether mandatory or voluntary, confidential or open to the public, does not automatically improve communication.

Why is the current PPDC successful?

1. The Plastic Pipe Data Collection Committee is composed of a government industry team, and therefore all important stakeholders are involved in the process.
2. The mission of the PPDC is to provide policy guidance on the collection of data and sharing of information. Inherent in this mission is the process of using the expertise of the stakeholders involved in the committee.
3. The PPDC is voluntary and designed to address the confidentiality concerns of those that participate. The more than 160 operators who volunteered to participate in the study are engaged and want to make the process successful.
4. The PPDC uses data only from the failure of in-service piping, and therefore avoids broader reporting that can skew the data analysis.
5. The administrator of the PPDC is the American Gas Association. AGA has no voting rights and no vested interests in the outcome of the PPDC work products. The administrator does not control the data; instead the administrator is an impartial entity that follows the consensus instructions of the government-industry team.
6. The PPDC has an extensive quality-control and quality-assurance process. The administrator is in contact with operators that submit data to the PPDC and checks for accuracy. Operators who have voluntarily become involved have looked at the reporting criteria and work to ensure that good data is submitted into the database. One hundred percent participation of operators is not needed because the volunteer operators

represent 74% of the mileage of plastic pipe in the United States. This is far more than is necessary for statistical purposes. Finally, the PPDC developed a 72 page instruction guide to help operators understand how the plastic pipe database works and what type of information to submit into the plastic pipe database.

The elements that make the PPDC successful are absent from the proposed rule in section 192.1009, which seeks to set up a mandatory plastic pipe reporting system. AGA makes the following observations about the proposed mandatory plastic pipe data reporting system:

1. The MPPDRS does not have a government-industry team to provide oversight and policy guidance. It has no established provisions to provide guidance and policy decisions to operators.
2. The reporting system is mandatory and has no provisions for operator input.
3. The reporting system has no restrictions on limiting data to in-service piping or excluding plastic pipe damaged during excavation.
4. The proposal would have PHMSA as an administrator. This is problematic because all submissions would be public records. PHMSA has vested interests in the database results and could not operate as an impartial administrator.
5. The mandatory reporting could create public records in which the disclosure could create unnecessary litigation for operators, manufacturers, the database administrator, PHMSA, and state regulators.
6. There are no provisions in the proposed rule for quality assurance and quality control of data submitted. The proposed rule would require operators to record and report information such as material type, manufacturer, lot number, and date of manufacture. Unfortunately, this information has not always been required to be permanently marked and/or permanently legible on pipe or fittings and therefore may not be available to be read, recorded and reported. This would create enforcement issues and unfairly punish operators for a lack of past standards requiring this information.
7. The proposal seeks to have 100% submission of all plastic pipe failures from all operators. This has the potential to create problems because there will likely be many operators that do not have guidance or technical expertise to submit appropriate failure data. Poor data such as failure from third party damage, or

incorrect classification can be worse than having no data at all, because it leads to wrong conclusions.

In summary, the proposed rule for mandatory plastic pipe data report system simply provides that operators must submit data and that one entity will be the administrator of the database. A comparison of the voluntary PPDC to the mandatory proposed plastic pipe reporting system shows that the mandatory system is easier to establish and probably easier to maintain. However, it does not provide the benefits of improved understanding of plastic pipe performance or enhancing safety, because it has few of the elements that make the existing PPDC successful. Therefore, AGA suggests that PHMSA delete requirements for a mandatory plastic pipe reporting system and work to modify the PPDC to make its communications more effective.

AGA provides what it believes are basic modifications that can be included in the successful PPDC system. After the discussion of suggested modifications, AGA provides answers to questions PHMSA presented in the federal register regarding plastic pipe data reporting. AGA hopes these answers help to clarify the benefits and barriers in operating a plastic pipe data system on a national level.

Modifications to the PPDC

There are improvements that can be made to the PPDC. The improvements do not have to be codified as part of the DIMP rulemaking. AGA has submitted comments herein that it believes are adequate to ensure the safety of plastic pipe installation. Modifications of the PPDC can be made separately from the rulemaking process.

AGA is willing to end its role as administrator for the PPDC. AGA accepted the role as an impartial administrator, follows the orders of the PPDC committee, and serves at the discretion of the PPDC. AGA receives no compensation, but spends approximately 0.3 man-years each year to administer the PPDC database[4]. AGA believes it has done an exceptional job of meeting the needs of the PPDC and will continue to serve as the administrator if the PPDC wants it to continue in that capacity and the service promotes pipeline safety.

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[4] The man-years were 0.5 to .75 in the early years of PPDC development.

Finally, AGA believes that many operators already include the threat of plastic pipe failure as one of the threats in their operating and maintenance plans. AGA expects it to be one of the lowest threats because of the improved properties of plastic.

If PHMSA wishes to codify operators addressing plastic pipe failure, AGA suggests that section 192.1009 be titled "What operators must do to manage plastic pipe integrity". The operative language should state that operators should periodically review government and industry advisories about plastic pipe; document failures of plastic pipe; evaluate the performance of plastic in their distribution system; and include appropriate actions in the integrity management plan to manage plastic pipe that has been documented to be susceptible to failure. Attempting to codify mandatory data submissions and concurrently operating a voluntary, confidential program like the PPDC creates legal liabilities for PHMSA and all parties involved.

Proposed Rule Scope Limitations Regarding Plastic Pipe Data

In the AGA DIMP Chicago workshop there were questions raised as to whether PHMSA intended "other materials containing plastic" to be included in the mandatory plastic pipe database. AGA found no information in the proposed rule language or the preamble providing notice that PHMSA was proposing to expand the data collection beyond plastic pipe. Specifically, there is no reference to failure of materials containing plastic (*including fittings, couplings, valves, joints and other equipment*).

The Administrative Procedures Act and relevant case law bars federal agencies from promulgating final rules that include substantive requirements for which notice and opportunity to comment were not provided to the public.

Additionally, even if PHMSA gave adequate notice to expand the data collection to fittings, couplings, valves, joints, and other equipment that contain plastic, there are limitations that make the expansion impractical. Experience with the PPDC shows that data generated from using plastic material from less than 10 manufacturers generates nearly 100 graphs of possible trends. Expanding a mandatory database to materials and equipment containing plastic from thousands of service providers that design, fabricate and install couplings, valves, joints, and other equipment would increase the database complexity a thousand fold. This broad and unfocused database would be impossible to manage and provide unreliable information.

PHMSA seeks comment on the following issues:

Changes PHMSA would consider valuable include the following:

Changing the current system of data collection, analysis, and communication to allow all operators better access to information on ''suspect'' materials in their systems (once analysis identifies a potential generic problem);

Answer: AGA has not received correspondence from operators expressing concern about the level of communication from the PPDC. The annual reports of PPDC data analysis are posted on the AGA web site for operator and public access. This includes the conclusion about "suspect" pipe. The AGA website also contains the latest versions of Frequently Asked Questions, data collection forms, form instruction, definitions, PPDC rosters, previous annual reports, a data collection PowerPoint tutorial entitled "Plastic Pipe Data Collection," a manufacturers database, and a timeline of events related to plastic piping. The link for the website is:
http://www.aga.org/Kc/resourcesbydiscipline/OperationsEngineering/ppdp/

PHMSA is co-chair with a gas utility operator. PHMSA, NAPSR, NARUC, and NTSB have copies of all PPDC reports and the committee encourages them to distribute the reports. The PPDC's communications with operators, and PHMSA's state partners, can be improved. However, improved communication is primarily separate from the collection and analysis of data.

Adding new requirements to facilitate operator use of PPDC information.

Answer: As stated above, operators have taken steps to address the conclusions of the PPDC annual reports. Five suspect plastic materials have been found. PHMSA issued advisories about the suspect plastic materials. AGA forwarded PHMSA advisories to all its members. AGA believes that operators have taken prudent action in response to PPDC annual reports and PHMSA advisories on plastic pipe. Nevertheless, AGA believes the final rule should require operators to incorporate the PPDC annual report conclusions and PHMSA advisories on plastic pipe into DIMP plans.

Adding requirements for information gathering on existing installed piping and equipment when normal operation and maintenance exposes the pipe.

Answer: AGA believes it is valuable to document information about existing piping and equipment when normal operations and maintenance exposes the pipe. However, there are technical problems that make it unfeasible for most, and perhaps all operators, to effectively implement this type of database system currently. Steel piping corrosion rates can be valuable information for exposed pipe. Attempting to document the millions of different plastic pipe lot numbers and millions of different couplings installed would require database systems several orders of magnitude more complicated. Work needs to be done to establish the technology to make this type of data infrastructure feasible in the gas utility industry. This type of excessive data collection should not be a requirement in the DIMP final rule.

PHMSA invites public comment on whether some other reporting frequency is preferable and adequate to identify trends (e.g., quarterly reporting, annual reporting).

Answer: The proposed mandatory plastic pipe reporting, 90-days after a failure, is problematic. The 90-day rule sets up tracking and enforcement issues for operators and state regulators that are unnecessary. Every anomaly involving plastic pipe material would have to be investigated and documented to make sure the anomaly was some other cause rather than material failure that did not require the 90-day reporting.

If PHMSA required plastic pipe failure reporting after each event, it would create several problems for the database manager. It is much more efficient for the database QA/QC manager to receive data or a negative report from each company on a set schedule. The 90-day requirement has the potential for reports being submitted 365 days a year that require QA/QC. The 90-day reporting requirement creates unnecessary compliance tracking for operators and state regulators.

The proposed requirements to collect and report data on plastic pipe failures from the final rule may not be necessary if another group agrees to perform these functions. PHMSA invites comments on the appropriateness of the proposed reporting requirements.

Answer: As stated previously, AGA believes that modification of the PPDC is the preferable option and creating a mandatory plastic pipe reporting system as suggested in the proposed rule is not necessary.

Plastic pipe markings

PHMSA invites comments on the desirability of requiring permanent markings on plastic pipe, on the related technical and logistical issues, and on its proposed approach to rely on ASTM to establish appropriate standards.

Answer: Plastic pipe marking is a good topic for discussion, but it is not necessary for DIMP and should not be a part of the final rule. AGA believes resolution of this issue rests primarily with plastic pipe manufacturers. They have responsibility for the manufacturing and technical issues that would control pipeline markings. Plastic pipe, as currently manufactured, is marked in accordance with ASTM D2513-99 requirements, which require manufacturers to make their markings legible, visible, and permanent. However, there are few requirements within the ASTM standards to permanently mark fittings, especially small diameter fittings. It would likely require new technology to develop new and improved ways to mark and track all plastic pipe appurtenances and fittings. Additionally, even if marking systems are created, AGA believes most operators do not possess the data infrastructure to record and properly manage data from each piece of plastic pipe. The knowledge requirements of 49 CFR 192.1007(a) are sufficient to manage pipeline integrity.

§ 192.1011 When must an Excess Flow Valve (EFV) be installed?

AGA acknowledges that the 2006 PIPES Act required PHMSA to mandate the installation of EFVs, for appropriate operating conditions. Approximately 50% of AGA member companies have been voluntarily installing EFVs since 2003, and that figure has increased steadily every year since. Almost 100% of AGA member companies now voluntarily install EFVs. AGA understands that the overall experience of these operators has been positive. The reliability of EFVs has improved substantially since they were first introduced to the industry.

Over the years, AGA has conducted various workshops and forums for its members in an effort to educate them on practices and policies in installing EFVs in a distribution system. The most recent event was an audio session held February 15, 2007 in which 35 member companies participated and learned from the experiences of two operators who have been voluntarily installing EFVs.

There are three specific items AGA would like to raise regarding the language reflected in 192.1011 *When Must an Excess Flow Valve (EFV) be installed*?

1. 192.1011(b)(4) allows an operator to forego an EFV "*if an EFV meeting performance requirements in 192.381 is not commercially available to the operator*." AGA agrees with the language as written. There may be some residential services that are so large as to not be practical for EFVs.

2. In the NPRM, PHSMA logically proposes to delete 192.383, which afforded operators the flexibility to either perform voluntary installation or customer notification of EFVs. Although AGA agrees this section should be terminated, doing so would essentially leave 192.381 under Subpart H. AGA suggests that 192.381 be modified so that, at a minimum, it contains a reference to 192.1011 which contains the provision that operators must install the EFVs. As proposed, the EFV performance criteria shows up first in the Federal Code and the requirement stating they are required does not appear until Subpart P. The added language should simply state that installation of EFVs is mandatory for single-family residential services for new installations or full service replacements, where operating conditions are applicable. The alternative is to move the proposed language in 192.1011 to Subpart H so that it appears in the portion of the code titled "Customer Meters, Service Regulators, and Service Lines". AGA's proposed changes in Appendix A reflect this option.

3. AGA believes that it was not the intent of Congress to mandate the installation of excess flow valves on branch services. Congress expressly limited the statute to single family residences. There is some benefit to installing EFVs in branch services depending on specific configurations and operating conditions.

> Operators may decide to develop O&M procedures that require the installation of EFVs on certain branched or share services, but that is a discretionary measure. It is AGA's understanding that PHMSA also believes the statute limits the mandate to single family homes. AGA suggests that this be reflected under 192.1011 and clarified in the preamble for the final rule. Branch services installations are commonly used throughout the gas distribution industry and this is an important clarification.

Finally, it is important to note that AGA does not believe that there is sufficient operator experience to support the use of EFVs in applications other than single-family, residential homes for services operating at 10 psig or higher in instances of new service installations or complete service replacements. Furthermore, there must always be the opportunity for an operator to justify the absence of an EFV when circumstances exist which would render the EFVs ineffective (such as increased liquids, contaminants, or highly variable gas loads).

192.1013 How does an operator file a report with PHMSA?

AGA has no comments on this subsection and supports the paragraph as written.

192.1015 What records must an operator keep?

AGA is concerned with the proposed requirements under 192.1015, particularly parts (c), (d) and (e). AGA understands that under any performance-based regulation such as DIMP, operators will be expected to retain records demonstrating judgment and actions taken to mitigate threats. Rather than requiring "*a written procedure for ranking the threats*" as reflected in 192.1015(c), AGA suggests the language be revised to: "*a description of how threats are ranked*". A detailed procedure or guide is not needed to perform risk-ranking; a company simply needs to be able to explain how risk-ranking is done under its DIMP plan.

AGA believes the requirements outlined in (d) and (e) are incredibly labor-intensive and burdensome. As described, operators would be expected to keep anything which has even a remote possibility of showing the operator's rationale for making any type of addition or change to its DIMP plan. When one considers the mileage of distribution main and number of services that are in the scope of an operator's DIMP plan, it quickly becomes apparent that this provision is impracticable. Gas utility operators and state regulators would be required to inspect mountains of paperwork and information.

Natural gas transmission integrity management has a provision in 49 CFR 192 Subpart O requiring a pipeline operator to produce extensive documentation to justify its integrity management program. The differences are that the mileage of High Consequence Area pipe in Transmission Integrity is a fraction of the mileage of distribution mains and services under DIMP. Additionally, it is common to have 150 miles of uniform transmission pipe between compressor stations. Therefore, only one set of integrity management decisions is made per 150 miles of pipe. Section 192.1015 could require the gas utility to document decisions every mile or every few hundred feet, because of the diversity of distribution piping design.

It is not unreasonable to think that operators could spend thousands of hours of labor each year on only documentation and record-keeping, based upon the current proposed rule language. Instead, the Regulatory Analysis written by PHMSA stated that six (6) additional hours per year would be spent by an office clerk to satisfy the recordkeeping requirement in the NPRM.

AGA contends that PHMSA's Regulatory Analysis of record keeping requirements is inconsistent with the recordkeeping language in the proposed rule. The Regulatory Analysis on page 53-54 states, "*there is no expectation that the recordkeeping would require operators to hire additional personnel. Neither is there an expectation that the recordkeeping would require operators to acquire new computers or peripherals.*"

AGA supports the intent of the regulatory analysis, but believes the language in section 192.1015 is too prescriptive and would require excessive recordkeeping. Subsection (e) would require the operator to provide for review during inspection: "*Records identifying changes made to the IM program, or its elements, including a description of the change and the reason it was made*". At the initial stages of developing a DIMP plan, it is not unreasonable to think an operator might make changes to its plan on a weekly basis. Many of these changes may be insignificant in nature. Would PHMSA really expect an operator to explain hundreds or thousands of changes made that could be as minor as updating the soil type or cover surrounding a 2" gas main?

AGA suggests the language be revised so that only significant changes made to the integrity management program are documented, where significance is based upon the operator's discretion.

Administratively, the first paragraph of section 192.1015 should be designated section (a) and the subsequent paragraph letter designations should be changed accordingly. In this section the requirement to keep records for the life of the pipeline should be changed to 10 years. Records for welding, fusion and other information that are required to be kept for the life of the pipeline are stipulated in other sections of the pipeline safety code. The gas distribution integrity management is a system management process, and like performance records, all other records created for the subpart should be kept for 10 years.

192.1017 When may an operator deviate from required periodic inspections under this part?

For the distribution integrity management rule to be cost-beneficial and truly enhance safety, it must embrace alternative inspection intervals. There is only a finite amount of resources to build capital projects and perform operations and maintenance. To effectively manage pipeline operations, an operator needs the flexibility to allocate resources to areas that pose the biggest risks and increase expenditures where the risks are higher.

The pipeline safety code was promulgated in the 1970s, when there was limited or no ability to develop computer databases to distinguish the different risk profiles in an operator's system. While the code is an excellent safety document, much of the code treats all distribution pipeline facilities as if they have the same level of risks. Therefore, a service line that was installed in 1940 is inspected for atmospheric corrosion every three years just like a pipeline that was installed in 2008. The existing code actually reduces the economic incentive to make some pipeline replacements, because the new facility will be subject to the same operation and maintenance costs for inspections as decades-old facilities.

Therefore, AGA supports section 49 CFR 192.1017 as written by PHMSA. The language is prudent and ensures that proposed changes for inspection intervals will not significantly increase risks. It requires that the alternative inspection intervals provide a satisfactory level of safety.

AGA has been informed that some state regulators and operators have administrative concerns about implementing this section of the rule. Among those concerns are:

- There is little or no incentive for states to approve alternative intervals;
- Operators have little or no influence to persuade states to change intervals;
- There is no guidance regarding how to evaluate alternative intervals or obtain administrative approval;
- There is no identified role for PHMSA in promoting alternative intervals; and
- It is not clear that PHMSA is delegating its authority to allow states to make the determination on alternative inspection intervals without PHMSA approval.

These are valid concerns, but they should have no bearing on the rulemaking language. The administrative issues will not likely be resolved during rulemaking. Implementation of alternative inspection intervals will not occur immediately after the final rule. Time will be needed to collect and analyze data and assess risks. PHMSA, state regulators and operators can develop guidance for evaluating alternative inspection intervals in forums separate from the rulemaking process. AGA agrees with state regulators that the implementation of alternative inspection intervals will have to be completed through state administrative processes.

AGA provides in its comments preliminary statistical information generated by the government–industry task group that is evaluating the inspection intervals for atmospheric corrosion and leakage surveys required by 49 CFR 192.481 and 192.723, respectively. A final report is planned for November 2008. AGA hopes that this information will provide a concrete example of some of the inefficiencies in the pipeline safety code and how analysis of data can promote the development and the use of alternative inspection intervals.

Atmospheric Corrosion and Leakage Surveys

The proposed section 192.1017 gives regulators and operators the flexibility of tailoring the pipeline safety code to adjust inspection intervals based upon risks. This improves pipeline safety by allowing operating and maintenance resources to be allocated more efficiently. Currently, operators and state regulators can only implement inspection intervals that are equal or more stringent than the federal pipeline safety code. Even if the federal code has known inefficiencies, there is no option for relief except the burdensome waiver process.

Federal regulations require pipeline operators to inspect service lines at least every 5 years for leakage (192.723) and every 3 years for atmospheric corrosion (192.481). The code did not align the leak and corrosion surveys. Therefore, the pipeline safety code essentially mandates inspections of a service line on years 3, 5, 6, 9 and 10. To avoid the inherent inefficiency of the staggered inspections of the same piping, many operators increased the leakage survey frequency from five to three years. This allows combined atmospheric corrosion and leakage surveys on years 3, 6, and 9. The code does not allow extending the corrosion inspection to five years. It may be reasonable for some states to use proposed section 192.1017 to change the corrosion inspection interval to five years if operator data shows that the change will not significantly increase risks and provides an adequate level of safety.

Table 1 shows the estimated national cost of the inspection options. The estimates assume an average cost of $20.00 for both types of inspections for 75 million services.

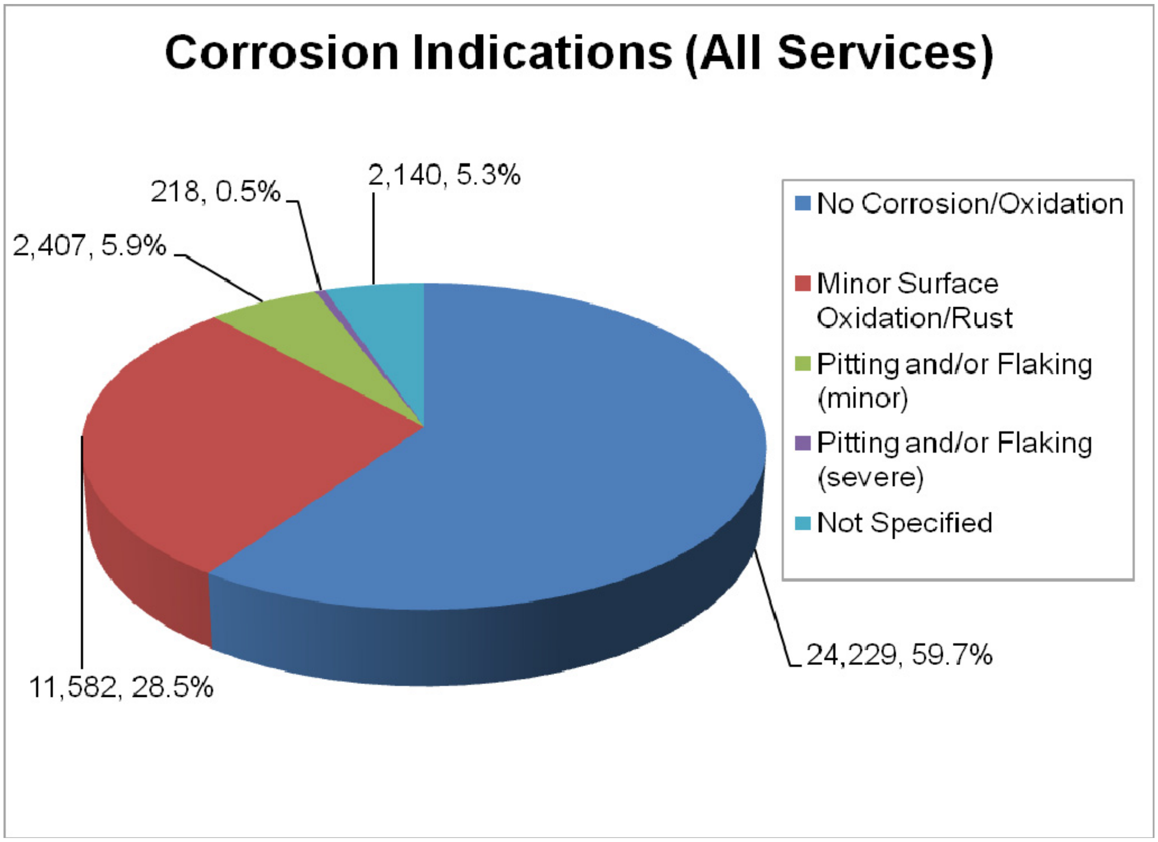
Table 1

Inspection options	Million services per year	Cost
Staggered inspections per code requirements	37.5	$750,000,000
Combined inspections every three years	25	$500,000,000
Combined inspections every five years	15	$300,000,000

AGA hired an independent consultant to work with operators and regulators to evaluate the effectiveness of corrosion and leakage inspections. Some preliminary results of the

67,000 combined corrosion and leakage inspections that were conducted over two months, throughout the nation, are presented in these comments. Chart 1 indicates that only a very small subset of piping shows atmospheric corrosion.

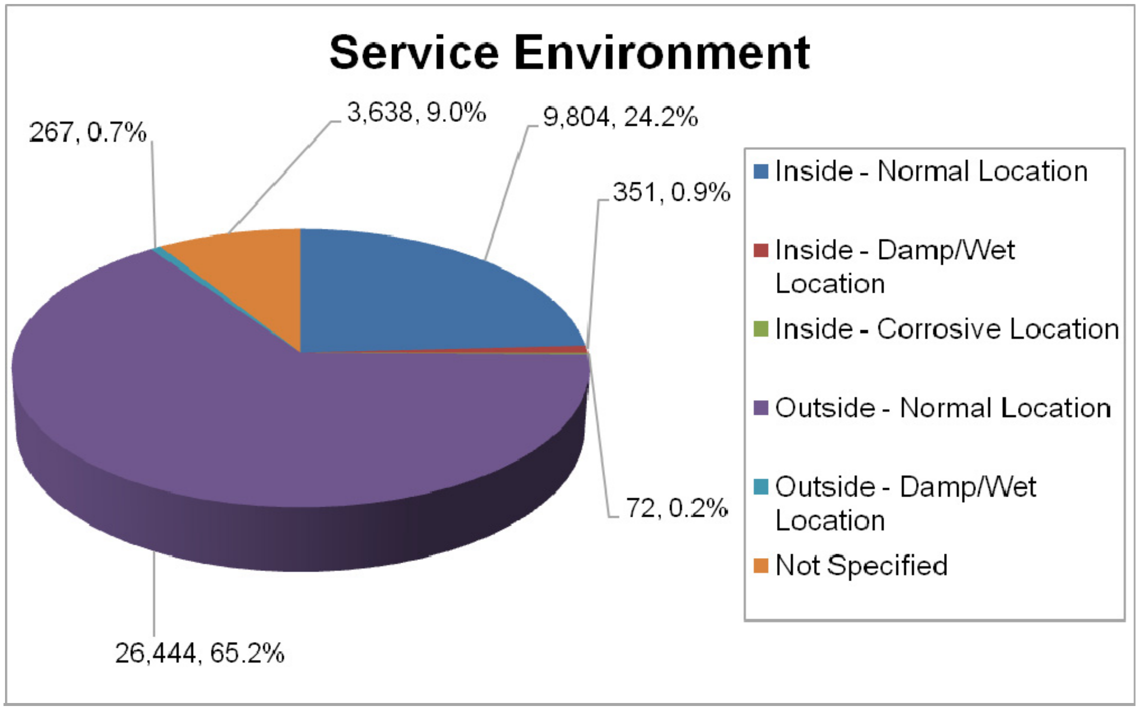
Chart 1



Some pipeline segments experience essentially no atmospheric corrosion. Yet, the code requires operators to repeatedly inspect these piping segments. The pipeline safety code does not require operators to evaluate whether service lines are operating in an environment that promotes accelerated corrosion, or whether the environment is arid with extremely slow rates of corrosion. The AGA survey that produced these charts requested inspectors to document the environment. Chart 2 shows that operators can identify corrosive environments and most are considered not corrosive.[5]

[5] The data was collected by field personnel in the normal course of business. Pictures were provides to personnel to assist in grading corrosion.

Chart 2



If operators document that they can identify service lines in corrosive or non-corrosive environment, it may be practical to extend the intervals for service lines in non-corrosive environments and allocate operations and maintenance resources to higher risk threats to the pipeline system.

PHMSA seeks comment on the following issues:

What are the advantages and disadvantages of allowing operators and States to set intervals for each distribution operator on required activities using a risk-based approach driven by thorough analysis of individual operator performance data?

Answer: Risk-based data driven intervals are more efficient and effective than inspection intervals with no technical or operating basis. The risk-based intervals can improve safety and reduce cost. The disadvantage is that it takes more engineering work to establish, implement, and monitor risk-based intervals.

Should there be some limit on the amount by which an operator can deviate from currently-prescribed intervals (e.g., no more than twice the interval in the Federal regulation)?

Answer: No. PHMSA should stand by its decision to have risk-based data driven regulations. No arbitrary interval, such as twice the Federal interval, should be applied. The risk analysis will control the limit. The risk may determine that the interval should be twice as long or fifty percent shorter than the federal interval.

There will be a tendency for regulators and operators to consider whether the alternative inspection interval "provides an equivalent or greater level of safety" than the existing interval. This phrase has been historically used in pipeline safety. It is important to understand that it should be the risk assessment of the data that determines the inspection interval; <u>not</u> a comparison to the existing inspection interval. The dispositive issue is really not whether the alternative inspection interval provides an equivalent or greater level of safety than the existing inspection interval. New equipment and technology often make the rationale for the existing inspection interval almost irrelevant. The dispositive issue is, "Does the inspection interval continue to provide an effective level of safety?" PHMSA does an excellent job by using regulatory language to convey this concept. The NPRM states:

§ 192.1017 When may an operator deviate from required periodic inspections under this part?

(a) An operator may propose to reduce the frequency of periodic inspections and tests required in this part on the basis of the engineering analysis and risk assessment required by this subpart. Operators may propose reductions only where they can <u>demonstrate that the reduced frequency will not significantly increase risk.</u>

(b) An operator must submit its proposal to the PHMSA Associate Administrator for Pipeline Safety or the State agency responsible for oversight of the operator's system. PHMSA, or the applicable State oversight agency, may accept the proposal, with or without conditions and limitations, on a showing that the <u>adjusted interval provides a satisfactory level of pipeline safety.</u>

Time dependent threats can be used to provide examples of how to view the level of risk and satisfactory margins of safety. As an example, we can explore the transmission integrity management inspection interval of seven years, and the potential decision to extend the interval.

The seven year inspection interval was set by Congressional statute. The members of Congress had little or no data on the:

- Condition of existing pipe
- Metal loss on existing pipe
- Rate of metal loss on existing pipe
- Potential for metal loss to cause a pipeline rupture

With little or no technical information, the existing regulation had the safety objectives of ensuring operators determine the condition of existing pipe as soon as possible through a baseline assessment, and then re-inspect the pipe at an interval that was sufficiently short so that the pipe would not fail before the re-inspection.

However, once data on pipe condition and rate of metal loss was obtained from the baseline assessment, it was readily determinable what re-inspection interval would be reasonable before the threat of pipeline failure would become experienced. The data-based inspection interval is clearly more precise than the seven-year interval that was selected by Congress without the support of technical data. The 10-year baseline assessment and the 7-year reassessment interval were reasonable intervals to provide a level of safety given the limited amount of technical data available. A similar example was discussed for distribution service line inspection intervals.
As PHMSA notes in the preamble:

> *"[O]perators are now required to inspect pipelines potentially subject to atmospheric corrosion, including service lines entering customer gas meters, at least every three years. Many meters are located inside homes where, in many cases, no one is available during the day to provide access, and where the environment is unlikely to be particularly corrosive. Operators must arrange with residents for access, and must sometimes make multiple visits in order to complete their inspections. The industry is seeking regulatory changes based on these difficulties to reduce the frequency of required inspections of inside meters. An alternative approach might be for operators to establish that corrosion of pipelines in residences is low-risk, and to propose an alternate interval for conducting these inspections. States would have the flexibility to accept or modify operator adjustments to these inspection intervals based on their local circumstances and their understanding of operators' risk."*

A government industry task group has been formed to evaluate the effectiveness of atmospheric corrosion and leakage surveys. Inspection results from across the country are being analyzed to determine rates at which corrosion is detected in various geographic locations and various environmental conditions. The data analysis will be helpful as operator and regulators evaluate the effectiveness of inspection intervals and the data of individual operators.

How would a State establish guidance for implementing such a process?

Answer: The last five questions appear to assume that a State pipeline safety agency would independently evaluate alternative inspection intervals without any assistance from other parties. That may be the situation in the existing waiver process that often takes years to complete.

AGA envisions PHMSA providing leadership in bringing stakeholders together to develop general guidance for alternative inspection intervals. AGA anticipates that the performance of individual and collective inspection intervals will be evaluated by operators and regulators in technical studies. A government–industry task group has begun this process with atmospheric corrosion inspections and leakage surveys of service lines. The information will be made available for all stakeholders. General technical guidance can be developed and States can utilize the guidance for specific operator data within their jurisdiction.

A regulatory template would be helpful for regional or local application of alternative inspection intervals. The templates do not have to be rigid. The templates do not have to be codified in the regulatory process. Templates should be guidance that conveys to stakeholders what basic information is needed to obtain approval of alternative inspection intervals.

What additional performance data and analysis would be required?

Answer: AGA believes that PHMSA is actually asking, “What additional performance data and analysis is needed to show that the pipeline facility is likely to continue to safely operate until the next scheduled inspection?”

For example, the current inspection interval for atmospheric corrosion in all locations with no statistical analysis is three years. The data collection and analysis requirement will be determined as guidance for special permits is developed. It is not necessary or practical to attempt to develop these requirements in the 90-day DIMP comment period.

Data can be collected on a national basis that potentially shows the average corrosion rate for unprotected steel pipe is more than 20 years to lose half the wall thickness. Operators may supplement the national or regional corrosion rate data with specific corrosion rate data for their pipeline system.

What costs to the States would be associated with such a process?

Answer: The cost to states associated with the process should be minimal. The process should avoid the years of administrative actions required in the existing waiver process. The process should be a mixture of general data requirements that meet a national consensus, which is then locally applied using data from individual operators.

What cost savings to operators could result from such changes?

Answer: AGA believes there is no way for the DIMP regulation to be cost-beneficial without the adoption and implementation by states of alternative inspection intervals. PHMSA discussed eight different inspection intervals in the preamble. Chart 1 show that the estimated national cost reductions for aligning the service line inspections at five years versus the three year combined inspections is $200 million annually. Inspection intervals for all services cannot be lengthened because of inspection requirements for cast iron pipe, corrosive environments and other factors. If 50% of the services moved to a five year inspection interval the cost reductions would be $100 million per year.

On what basis should a State judge the operators' engineering basis adequate?

Answer: There will not be a single engineering basis for all alternative intervals. There needs to be a consensus for the engineering concept that supports the interval in which a pipeline can safely operate without the unwarranted risk event occurring (e.g. ASME B31.8 pressure tested pipe operating below 30% SMYS can safety operate for 20 years before reinspection). Once the technically based maximum duration is determined, a shorter safety interval may be selected that still provides an adequate margin of safety.

For example, are seven- and ten-year inspections acceptable for transmission integrity management re-inspections when the ASME standard states that the pipeline should operate safely for 20 years?

192.1019 What must a master meter or liquefied petroleum gas (LPG) operator do to implement this subpart?

AGA believes that master meter and liquefied petroleum gas operators should be required to implement distribution integrity management programs. However, the administrative requirements should be scalable to minimize the details required by operators of these relatively uncomplicated facilities.

Miscellaneous Issues

Low Stress Transmission Pipelines

PHMSA should consider expanding the scope of the distribution integrity management regulation to include natural gas transmission pipelines that operate at or below 30% SMYS. These transmission pipelines are integral parts of distribution systems. There are situations where the integrity of these pipelines is better managed within distribution integrity management than the transmission integrity management regulations of 49 CFR 192 Subpart O.

There are several ways to accomplish the regulation of low stress pipelines, including:

- Changing the transmission pipeline definition,
- Changing the scope of 49 CFR 192.1001 to include pipelines at or below 30% SMYS, or
- Modifying 49 CFR 192.1017 to provide the states the flexibility of modifying inspection intervals, as well as deciding if Subpart O or P is most appropriate to manage the integrity of low stress pipelines.

Adopting any of the options will require PHMSA to issue a new or supplemental notice to expand the rule to consider options for managing low stress pipelines. To provide as complete a record as possible, AGA has included in Appendix D the relevant sections of the Pipeline Safety Act of 2002 which clearly noted that the transmission definition in 49 CFR 192 could be modified to facilitate the pipelines that were regulated by the statutory mandate of 42 U.S.C. 60109.

Appendix E includes some of the AGA comments to the transmission integrity management rulemaking. These comments explained that low stress pipeline failure mechanisms are via leaks rather ruptures. Therefore, the transmission integrity management plans required in Subpart O, that were designed for high stress transmission lines, were not always consistent with operating practices of transmission pipelines in distribution systems. The comments state in relevant part,

> *"RSPA acknowledged that low stress pipelines pose less risk and require less stringent regulatory measures than higher stress pipelines. In the above referenced notice of proposed rulemaking RSPA stated,*
>
> *"Pipelines that operate at a stress level less than 30% SMYS fail differently (i.e., leak rather than rupture) from those operating at higher stress. Therefore, different integrity assurance techniques may be appropriate. These low stress pipes have been shown both by fracture mechanics analysis and by evaluation of failure experience data to fail by leaking, not by rupture. Therefore, the techniques most effective in assuring the integrity of these pipelines could reasonably involve a combination of integrity assessment techniques and enhanced leak detection."*

RSPA also stated,

> *"Current gas pipeline safety regulations recognize the reduced risk that low stress levels pose, and structure the requirements accordingly. Examples of different requirements for pipelines operating at lower stress are in § 192.65 (Transportation of pipe), § 192.227 (Qualification of welders), § 192.241 (Inspection and test of welds), § 192.309 (Repair of steel pipe), § 192.315 (Wrinkle bend in steel pipe), § 192.319 (installation of pipe in a ditch, § 192.505 (Strength requirements for steel pipeline to operate at a hoop stress of 30% or more of SMYS), § 192.711 (General requirements for repair procedures), and § 192.717 (Permanent field repair of leaks)."*

AGA's comments to the Transmission Integrity Management docket stated,

> "AGA agrees with RSPA's above referenced assessments and has previously highlighted these issues in comments submitted to the docket (docket items RSPA-2000-7666-73 and RSPA-2000-7666-86). In these previous comments, AGA argued that pipelines operating below 20% SMYS should be not be covered under the impending integrity management regulation. While AGA still believes that this is technically justified, AGA recognizes that the Pipeline Safety Act of 2002 does not give RSPA the flexibility to exclude such pipelines from the regulation. AGA would like to pursue a future effort to better address integrity management requirements for transmission pipelines operating at or below 20% SMYS. In the meantime, AGA is including the transmission

> pipelines operating below 20% SMYS in our proposal for addressing integrity assessments under the category of pipelines operating below 30% SMYS."

AGA believes PHMSA should revisit the issue of how best to manage the integrity of low stress gas transmission pipelines.

III. CONCLUSION

AGA appreciates the opportunity to comment on the proposed rule for distribution integrity management programs. PHMSA did an excellent job of bringing all stakeholders together to develop the DIMP Phase 1 report, which provided the framework for the proposed rule. AGA has suggested changes that it believes will improve the final rule. Some issues can be resolved during the rulemaking process. Other issues, such as implementing alternative inspection intervals, will require stakeholders to continue to work together after promulgation of the final rule.

It is clear that industry, state and federal regulators have the common goal of operating a safe and reliable natural gas distribution system. The excellent safety record of the industry reflects well on industry and government. AGA believes the distribution integrity management regulation is another step in continuing the goal of safety and reliability.

Respectfully submitted,

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AMERICAN GAS ASSOCIATION

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APPENDIX A

The strike through text denotes deletions. The underlined text denotes additions.

Subpart P—Gas Distribution Pipeline Integrity Management (IM)

Sec. 192.1001 **What do the regulations in this subpart cover?**

General. This subpart prescribes minimum requirements for an IM program for any gas distribution pipeline covered under this part. A gas distribution operator, other than a master meter or liquefied petroleum (LPG) operator, must follow the requirements in §§ 192.1005 through 192.1017 of this subpart. A master meter operator or LPG operator of a gas distribution pipeline must follow the requirements in § 192.1019 of this subpart.

Sec. 192.1003 **What definitions apply to this subpart?**

The following definitions apply to this subpart:

Excavation Damage means any impact or exposure resulting in the ~~repair or replacement of an underground facility, related appurtenance, or materials supporting~~ immediate release of gas from the pipeline.

Sec. 192.1005 **What must a gas distribution operator (other than a master meter or LPG operator) do to implement this subpart?**

(a) Dates. No later than [INSERT DATE ~~18~~ 24 MONTHS AFTER PUBLICATION OF THE FINAL RULE IN THE Federal Register] an operator of a gas distribution pipeline must develop and ~~fully~~ implement the framework for a written IM program. The IM program must contain the elements described in § 192.1007.

(b) Procedures. An operator's program must have written procedures ~~describing the processes~~ for developing, implementing and periodically improving each of the required elements

Sec. 192.1007 **What are the required integrity management (IM) program elements?**

(a) Knowledge. An operator must demonstrate an understanding of the gas distribution system.

(1) Identify the characteristics of the system and the environmental factors that are necessary to assess the applicable threats and risks to the gas distribution system.

(2) Understand the information gained from past design and operations.

(3) Identify additional information needed and provide a plan for gaining that information over time through normal activities.

(4) Develop a process by which the ~~program~~ knowledge base will be ~~continually~~ periodically refined and improved

(5) Provide for the capture and retention of data on any piping system installed after the operator's IM program becomes effective. The data must include, at a minimum, the location where the new piping and appurtenances are installed and the material of which they are constructed.

(b) Identify threats. The operator must consider the following categories of threats to each gas distribution pipeline: corrosion, natural forces, excavation damage, other outside force damage, material and ~~or~~ weld ~~failure~~, equipment malfunction, inappropriate operation, and any other concerns that could threaten the integrity of the pipeline.

An operator must gather data from the following sources to identify ~~existing and potential~~ threats: incident and leak history, corrosion control records, ~~continuing surveillance records~~, patrolling records, maintenance history, and ''one call'' and excavation damage experience.

~~In considering the threat of inappropriate operation, the operator must evaluate the contribution of human error to risk and the potential role of people in preventing and mitigating the impact of events contributing to risk. This evaluation must also consider the contribution of existing DOT requirements applicable to the operator's system (e.g., Operator Qualification, Drug and Alcohol Testing) in mitigating risk.~~

(c) Evaluate and prioritize risk. An operator must evaluate the risks associated with its distribution pipeline system. In this evaluation, the operator must determine the relative probability of each threat and estimate and prioritize the risks posed to the pipeline system. This evaluation must consider each applicable current and potential threat, the likelihood of failure associated with each threat, and the potential consequences of such a failure. An operator may subdivide the system into regions (areas within a distribution system consisting of mains, services and other appurtenances) with similar characteristics and reasonably consistent risk, and for which similar actions would be effective in reducing risk.

(d) Identify and implement measures to address risks. Determine and implement measures designed to reduce the risks from failure of its gas distribution pipeline system. These measures must include implementing an effective leak management program and ~~enhancing~~ <u>evaluating</u> the ~~operator's~~ damage prevention program required under § 192.614 of this part. ~~To address risks posed by inappropriate operation, an operator's written IM program must contain a separate section with a heading 'Assuring Individual Performance'. In that section, an operator must list risk management measures to evaluate and manage the contribution of human error and intervention to risk (e.g., changes to the role or expertise of people), and implement measures appropriate to address the risk. In addition, this section of the written IM program must consider existing programs the operator has implemented to comply with § 192.614 (damage prevention programs); § 192.616 (public awareness); Subpart N of this Part (qualification of pipeline personnel), and 49 CFR Part 199 (drug and alcohol testing).~~

(e) Measure performance, monitor results, and evaluate effectiveness.

(1) Develop and monitor performance measures from an established baseline to evaluate the effectiveness of its IM program. An operator must consider the results of its performance monitoring in periodically re-evaluating the threats and risks. These performance measures must include the following:

(i) Number of hazardous leaks either eliminated or repaired, per § 192.703(c), categorized by cause;

(ii) Number of excavation damages;

(iii) Number of excavation tickets (receipt of information by the underground facility operator from the notification center);

(iv) Number of EFVs installed;

(v) Total number of leaks either eliminated or repaired, categorized by cause;

(vi) Number of hazardous leaks either eliminated or repaired per § 192.703(c), categorized by material; and

(vii) Any additional measures to evaluate the effectiveness of the operator's program in controlling each identified threat.

(f) Periodic Evaluation ~~and Improvement~~. An operator must ~~continually~~ periodically re-evaluate threats and risks on its entire system and consider the relevance of threats in one location to other areas. ~~In addition, each operator must periodically evaluate the effectiveness of its program for assuring individual performance to reassess the contribution of human error to risk and to identify opportunities to intervene to reduce further the human contribution to risk (e.g., improve targeting of damage prevention efforts).~~ Each operator must determine the appropriate period for conducting complete program evaluations based on the complexity of its system and changes in factors affecting the risk of failure. An operator must conduct a complete program reevaluation at least every five years. The operator must consider the results of the performance monitoring in these evaluations.

(g) Report results. Report the four measures listed in paragraphs (e)(1)(i) through (e)(1)(iv) of this section, annually by March 15, to PHMSA as part of the annual report required by § 191.11 of this chapter. An operator also must report these four measures to the State pipeline safety authority in the State where the gas distribution pipeline is located.

Sec. 192.1009 **What must an operator do to manage ~~report when~~ plastic pipe ~~fails~~?**

(a) Operators must consider the threat of plastic in-service piping material failure as a threat in section 192.1007 and at a minimum:

(1) periodically review government and industry advisories about plastic pipe,
(2) document failures of plastic pipe as,
(3) evaluate the performance of plastic within its distribution system,
(4) include appropriate action in the integrity management plan to manage plastic pipe that has been identified to be susceptible to failure.

~~Each operator must report information relating to each material failure of plastic pipe (including fittings, couplings, valves and joints) no later than 90 days after failure. This information must include, at a minimum, location of the failure in the system, nominal pipe size, material type, nature of failure including any contribution of local pipeline environment, pipe manufacturer, lot number and date of manufacture, and other information that can be found in markings on the failed pipe. An operator must send the information report as indicated in § 192.1013. An operator must also report this information to the State pipeline safety authority in the State where the gas distribution pipeline is located.~~

Subpart H: Customer Meters, Service Regulators, and Service Lines
Sec. 192.383~~1011~~ **When must an Excess Flow Valve (EFV) be installed?**

(a) General requirements. This section only applies to new or entirely replaced service lines serving single-family residences. An EFV installation must comply with the requirements in § 192.381.

(b) Installation required. The operator must install an EFV on the service line installed or entirely replaced after [INSERT DATE 90 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE Federal Register], unless one or more of the following conditions is present:

(1) The service line does not operate at a pressure of 10 psig or greater throughout the year;
(2) The operator has prior experience with contaminants in the gas stream that could interfere with the EFV's operation or cause loss of service to a residence;
(3) An EFV could interfere with necessary operation or maintenance activities, such as blowing liquids from the line; or
(4) An EFV meeting performance requirements in § 192.381 is not commercially available to the operator.
(5) On branch services.

Sec. 192.1011~~3~~ **How does an operator file a report with PHMSA?**

An operator must send any performance report required by this subpart to the Information Resource Manager as follows:

(a) Through the online electronic reporting system available at PHMSA's home page at http://phmsa.dot.gov;
(b) Via facsimile to (202) 493–2311; or
(c) Mail: PHMSA—Information Resource Manager, U.S. Department of Transportation-East Building, 1200 New Jersey Avenue, SE., Washington, DC 20590.

Sec. 192.1015 **What records must an operator keep?**

(a) ~~Except for the performance measures records required in § 192.1007,~~ An operator must maintain~~, for the useful life of the pipeline,~~ records demonstrating compliance with the requirements of this subpart for 10 years. At a minimum, an operator must maintain the following records for review during an inspection:

(1) A written IM program in accordance with § 192.1005;
(2) Documents supporting threat identification;
(3) A description of how threats are ranked ~~written procedure for ranking the threats~~;
(4) Documents to support ~~any decision, analysis, or process developed and used~~ significant decisions made to implement and evaluate each element of the IM program;
(5) Records identifying significant changes made to the elements of the IM program, ~~or its elements, including a description of the change and the reason it was made~~; and
(6) Records on performance measures. ~~However, an operator must only retain records of performance measures for ten years.~~

Sec. 192.1015~~7~~ **When may an operator deviate from required periodic inspections under this part?**

(a) An operator may propose to reduce the frequency of periodic inspections and tests required in this part on the basis of the engineering analysis and risk assessment required by this subpart. Operators may propose reductions only where they can demonstrate that the reduced frequency will not significantly increase risk.

(b) An operator must submit its proposal to the PHMSA Associate Administrator for Pipeline Safety or the State agency responsible for oversight of the operator's system. PHMSA, or the applicable State oversight agency, may accept the proposal, with or without conditions and limitations, on a showing that the adjusted interval provides a satisfactory level of pipeline safety.

Sec. 192.1017~~9~~ **What must a master meter or liquefied petroleum gas (LPG) operator do to implement this subpart?**

(a) General. No later than [INSERT DATE ~~18~~ 24 MONTHS AFTER PUBLICATION OF THE FINAL RULE IN THE Federal Register] the operator of a master meter or a liquefied petroleum gas (LPG) gas distribution pipeline must develop and ~~fully~~ implement a written IM program. The IM program must contain, at a minimum, elements in paragraphs (a)(1) through (a)(5) of this section. The IM program for these pipelines should reflect the relative simplicity of these types of systems.

(1) Infrastructure knowledge. The operator must demonstrate knowledge of the system's infrastructure, which, to the extent known, should include the approximate location and material of its distribution system. The operator must identify additional information needed and provide a plan for gaining knowledge over time through normal activities.

(2) Identify threats. The operator must consider, at minimum, the following categories of threats (existing and potential): corrosion, natural forces, excavation damage, other outside force damage, material or weld failure, equipment malfunction and inappropriate operation.

(3) Identify and implement measures to mitigate risks. The operator must determine and implement measures designed to reduce the risks from failure of its pipeline system.

(4) Measure performance, monitor results, and evaluate effectiveness. The operator must develop and monitor performance measures on the number of leaks eliminated or repaired on its pipeline system and their causes.

(5) Periodic evaluation and improvement. The operator must determine the appropriate period for conducting IM program evaluations based on the complexity of its system and changes in factors affecting the risk of failure. An operator must re-evaluate its entire program at least every five years. The operator must consider the results of the performance monitoring in these evaluations.

(b) Records. The operator must maintain, for ~~the useful life of the pipeline~~ 10 years, the following records:

(1) A written IM program in accordance with this section;

(2) Documents supporting threat identification; and

(3) Documents showing the location and material of all piping and appurtenances that are installed after the effective date of the operator's IM program and, to the extent known, the location and material of all pipe and appurtenances that were existing on the effective date of the operator's program.

APPENDIX B

Mission

The government-industry Plastic Pipe Database Committee (PPDC) is formed to develop and maintain a voluntary data collection process that supports the analysis of the frequency and causes of in-service plastic piping material failures.

Charter

The PPDC is composed of six stakeholders that include the American Gas Association (AGA), the American Public Gas Association (APGA), the U.S. Department of Transportation's Office of Pipeline Safety (OPS), the National Association of Pipeline Safety Representatives (NAPSR), the National Association of Regulatory Utility Commissioners (NARUC), and the Plastics Pipe Institute (PPI). Each stakeholder has two representatives.

Purpose. To improve the knowledge base of gas utility operators and regulators, and to address the recommendation of the National Transportation Safety Board (NTSB) to monitor and determine if any failure trends exist in the performance of older plastic piping materials.

Consensus. The PPDC will make all decisions within a consensus framework. Each stakeholder representative agrees not to initiate unilateral action on issues addressed by this committee.

Confidentiality. The data collection process will maintain the confidentiality of all participating gas utilities. All data will be submitted into a repository that ensures confidentiality. The AGA will undertake the role as the repository for the data. The data will be collected and placed into a plastic pipe failure database (PPFDB) until determined by the PPDC.

Database Access. To be determined by the PPDC at a later date.

Prospective Data. The focus of this initiative is placed on prospective data. The PPDC will consider including voluntary historical data in the PPFDB.

Third-Party Damage. The PPDC will not collect third-party damage data directly from the voluntary participants. Any third-party damage data collected may be received through the Common Ground Alliance (CGA). The PPDC will follow the data collection process by CGA.

Cost Sharing. The stakeholders agree that the costs associated with this program will be borne in a fair and equitable manner among the parties.

Coordination. The PPDC will keep the NTSB fully advised of this initiative through OPS representatives.

APPENDIX B

DOT PLASTIC PIPE DATA COLLECTION AND SHARING INITIATIVE
PLASTIC PIPE DATABASE COMMITTEE (PPDC)
WRITTEN CONSENSUS SUMMARY

After the planning phase of the plastic pipe data gathering and sharing effort is over and implementation begins, this Written Consensus Summary will remain as a reference to rules representing consensus of the PPDC the industry voluntary data gathering, sharing and interpretation effort will function under. If the PPDC were to be ever replaced by another group, the Mission/Charter might have to be modified, but this Written Consensus Summary would remain to guide the voluntary data collection & sharing effort.[1]

A. The government-industry team developing the provisions of this initiative would be referred to hereafter as the “PLASTIC PIPE DATABASE COMMITTEE” (PPDC).

B. Definition of Consensus: “A decision which all members or designated alternates present at the meeting can agree upon. The decision may not be everyone's first choice, but they have heard it and everyone can live with it.” Consensus was reached on this definition and its use, provided an individual team member could request to “go on record” as not agreeing with the decision, but willing to live with it for the greater good. In the context of consensus, all PPDC members’ opinions have equal weight. An item of consensus by the PPDC is tentative until accepted by the respective member’s constituency before final consensus is reached on that item.

C. The Mission/Charter of the PPDC expresses the purpose of the PPDC as a group, and provides policy guidance on the data collection and sharing effort.

D. Participation in this data collection program by gas utility operators shall be on a voluntary basis.

E. Only failures of in-service piping will be included in the data collection effort. Installation errors caught by inspectors and corrected should not be included in the data collection effort.

F. Individual participants’ identity will be protected.

G. AGA will receive data and enter them into the database on behalf of the PPDC. It will thereafter maintain exclusive possession and custody of the database on behalf of the PPDC. Ultimate control over the data stored in the database shall be exercised jointly by all members of the PPDC. Express consensus of the PPDC must be obtained before any individual member of the PPDC (and/or entity employing or otherwise associated with that individual) may provide

[1] Note: The items in this Summary are derived from the PPDC meeting summaries. Items A-K are derived from the 1/26/00 Meeting Summary; items L-N are derived from the 3/1/00 Meeting Summary; Items G and M are further modified in accordance with the 8/23/00 Meeting Summary.

access to, dispose of or otherwise exercise control of any type over the database or the data it contains.

H. Individual states have the right to request data from individual operators, but states are urged to cooperate with the data collection program, rather than duplicating efforts.

I. AGA will act as a clearinghouse, setting up the database, collecting the data, and maintaining the database. Initial analysis of the failed sample to determine the cause of failure will be done by the participating company submitting the data to AGA.

J. In selecting the attributes of data to be collected by AGA, a criterion for whether the item is needed would be its relevance to determining trends in the data.

K. The PPDC shall solicit volunteers seeking to build a group that yields data representative of a cross-section of the industry, covering various geographical regions and plastic materials in service.

L. The Mission/Charter, Plastic Piping Failure Report form, Definitions and AGA Data Collection Procedures are part of this consensus summary document.

M. Analysis and interpretation of the collected data shall be performed only by the PPDC (or its surrogates), viewing the data simultaneously. After the process begins, the PPDC will decide whether the analysis of the data should include others.

N. Once the data collection effort starts, AGA will give a monthly report to the PPDC on progress in the data collection effort. At a time to be determined by the Committee, the PPDC will produce and issue a report based on joint conclusions about the data.

APPENDIX C

Plastic Piping Data Collection Initiative
Status Report
March 18, 2008

The Plastic Pipe Database Committee (PPDC), composed of members of the American Gas Association (AGA), American Public Gas Association (APGA), Plastics Pipe Institute (PPI), National Association of Regulatory Utility Commissioners (NARUC), National Association of Pipeline Safety Representatives (NAPSR), National Transportation Safety Board (NTSB) and U.S. Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA), has been coordinating the creation and maintenance of a database of in-service plastic piping (i.e. piping appurtenances) material failures with the objective of identifying possible material performance issues. Company participation in this initiative is voluntary and the database is designed to address the confidentiality concerns of the participants.

The data collection initiative arose from the NTSB Special Investigation Report *Brittle-Like Cracking in Plastic Pipe for Gas Service*[1]. The NTSB recommended that PHMSA determine how susceptible older plastic piping materials are to premature brittle-like cracking. The industry agreed to work with the regulatory community to voluntarily collect pertinent information to be placed into a secure database.

DOT statistics indicate there were approximately 577,562 miles of plastic main and 39.6 million plastic services installed in the distribution systems of approximately 1,397 gas companies in the U.S. at the end of 2006. These statistics indicate an increase of more than 33,500 miles of plastic main and 2.1 million services from 2005[2]. Historical statistics have shown a steady increase over the years in the miles of installed plastic main and the number of plastic services.

Approximately 162 companies have volunteered to participate in the Plastic Pipe Data Collection and Sharing Initiative. These companies operate 77% of the total mileage of installed plastic main in the U.S. and 80% of the total number of installed plastic services. The PPDC actively encourages additional voluntary participation to ensure the broadest coverage possible and to enhance the value of the database as a barometer of plastic material performance. AGA and APGA continue to encourage additional voluntary participation of their member companies. The NAPSR and NARUC discuss the PPDC at regional and national meetings and request that state representatives encourage operators within their states to participate in the PPDC data collection effort.

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[1] *Brittle-Like Cracking in Plastic Pipe For Gas Service*, NTSB Report No. NTSB/SIR-98/01, National Transportation Safety Board, Washington, D.C., April 1998.

[2] U.S. Department of Transportation statistics indicate approximately 544,000 miles of plastic main and 37.5 million plastic services were installed at the end of 2005.

Collected data include both actual through-wall failure information and negative reports (i.e., one-page forms completed by participating companies indicating that they had no failure data to submit during the month). The data supplied by volunteer participants in the plastic pipe data collection program are examined by the PPDC at each meeting to consider plastic material failures unrelated to third party damage in order to evaluate the performance of plastic pipe. Immediate third party damages are not collected or evaluated (except where delayed material failure occurs after the damage event) since this data is collected by the Common Ground Alliance and it does not provide an indication of the long-term performance of plastic piping materials.

Although the data is being reviewed by the PPDC, the data cannot be directly correlated to quantities of each material that may be in service across the United States. Therefore, the PPDC is not able to assess the failure rates of these materials. However, the failure data points reinforce what is already (and historically) known about certain older plastic piping. Some of these were identified in 2000 by a government-industry group[3] and have resulted in DOT Advisory Bulletins[4]. The bulletins can be found on the PHMSA website at http://ops.dot.gov. Historically known information includes the following plastic piping that has demonstrated a significantly lower resistance to stress intensification[5] resulting in material failure:

1. Century Utility Products polyethylene (PE) pipe produced from 1970 through 1974
2. DuPont Aldyl® A low ductile inner wall PE pipe manufactured from 1970 through 1972
3. PE pipe manufactured from PE 3306 resin
4. DuPont service punch tee with a white Delrin polyacetal insert
5. Plexco service tee with Celcon (polyacetal) cap

The data indicate that many of the early plastic piping products manufactured in the 1960s to early 1980s are more susceptible to brittle-like cracking (also known as slow crack growth) than newer vintage materials. Brittle-like cracking failures occur under conditions of stress intensification. Stress intensification is more common in fittings and joints. Operators should actively monitor the performance of their piping systems.

[3] Robert J. Hall, *Brittle-Like Cracking of Plastic Pipe*, Final Report No. DTRS56-96-C-0002-006, General Physics Corp., Columbia, Maryland, August 2000.
[4] DOT Advisory Bulletin ADB-02-07, *Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe*, Federal Register, Volume 67, Number 228, p. 70806, November 26, 2002 and Federal Register, Volume 67, Number 232, p. 72027, December 3, 2002.
[5] Stress intensification includes conditions such as rock impingement, squeeze off, soil settlement, bending, shear, over-tightening of caps.

Plastic materials, standards and manufacturing practices have steadily improved over the years. These enhancements have led to an improved ability to withstand stress intensification and have benefited long-term plastic gas piping system performance.

In an effort to assist the gas utilities, the Gas Piping Technology Committee (GPTC) has prepared guidance material that an operator can use when these older plastic pipe materials are known to be present in their piping system. The guidance material was published in May 2005, under Subpart L, Section 192.613, as part of Addendum No. 2 to the 2003 edition of the Guide.

In addition, the AGA Plastic Pipe Manual contains information on plastic pipeline materials, including factors affecting plastic piping performance, engineering consideration for plastic pipe utilization, procurement considerations and acceptance tests, installation guidance, personnel training, field inspection and pressure testing, operations and maintenance, and emergency control procedures.

Finally, the PPDC has compiled historical plastic material manufacturing information. This ongoing effort helps to identify the manufacturers of plastic pipe, fittings and appurtenances for gas distribution operations, including material designations, when the materials were produced, size ranges and other important information. Corrections and/or additions are encouraged and should be communicated to Kate Miller at AGA (kmiller@aga.org). It should be noted that operators are required to install piping that meets current regulations. This information should assist operators in the assessment of their plastic piping systems and is available on the AGA website, **www.aga.org**.

For the many miles of these older PE materials still in service in the U.S., the key unknown is the projected performance of these pipes. The rate process method (RPM) can be used to determine if there is an early transition to brittle-like properties of PE materials. The RPM can also be used to predict performance of PE materials at their inground temperatures and pressures based on both internal pressure as the primary load and secondary loads such as rock impingement and squeeze-off.[6]

AGA is available to help participants fill out the failure report or negative report forms if there are any questions by a participant. The AGA website contains the latest versions of Frequently

[6] Bragaw, C.G., "Prediction of Service of Polyethylene Gas Piping System," *Proceedings Seventh Plastic Fuel Gas Pipe Symposium*, pp. 20-24, 1980, and Bragaw, C.G., "Service Rating of Polyethylene Piping Systems by the Rate Process Method," *Proceedings Eighth P*….See NTSB page 19

Asked Questions , data collection forms, form instruction, definitions, PPDC rosters, previous annual reports, a data collection PowerPoint tutorial entitled “Plastic Pipe Data Collection” and further details on the goals of the plastic pipe database initiative.

With this status report, the PPDC continues to urge all natural gas distribution system operators to volunteer as active participants in this proactive and worthwhile initiative.

For additional information about this initiative, contact Kate Miller at AGA (by telephone 202 824-7342 or electronically at kmiller@aga.org).

APPENDIX C

PLASTIC PIPE DATA COLLECTION AND SHARING INITIATIVE

Annual Progress Report

February 11, 2007

Introduction

This is the sixth annual report on the progress of the Government-industry Plastic Pipe Data Collection and Sharing Initiative. This data collection initiative arose from a National Transportation Safety Board (NTSB) incident investigation and report that identified the cause of a 1994 incident in Waterloo, Iowa as "brittle-like cracking" of plastic pipe[7]. The NTSB recommended that the U.S. Department of Transportation's (DOT) Office of Pipeline Safety (OPS) determine how susceptible older plastic piping materials are to premature brittle-like cracking. The industry agreed to work with the regulatory community to voluntarily collect accurate and pertinent information to be placed into a secure database.

The Plastic Pipe Database Committee (PPDC), comprised of members of the American Gas Association (AGA), the American Public Gas Association (APGA), the Plastics Pipe Institute (PPI), the National Association of Regulatory Commissioners (NARUC), the National Association of Pipeline Safety Representatives (NAPSR), and the DOT, has been coordinating the creation of a database of in-service plastic piping material failures with the objective of identifying possible trends in the performance of these materials. Company participation in this initiative is voluntary and the database is designed to address the confidentiality concerns of the participants.

DOT statistics indicate there were approximately 544,000 miles of plastic main and 37.5 million plastic services installed in the distribution systems of approximately 1,450 gas companies in the U.S. at the end of 2005. These statistics indicates an increase of approximately 5,000 miles of plastic main and 700,000 services from 2004[8]. Historical statistics have shown a steady increase over the years in the miles of installed plastic main and the number of plastic services.

The data supplied by volunteer participants in the plastic pipe data collection program are examined by the PPDC at each meeting to consider plastic material failures unrelated to third party damage (except where delayed material failure occurs after the damage event) in order to evaluate the performance of plastic pipe. Immediate third party damages are not collected or evaluated since this data is collected by the Common Ground Alliance and it does not provide an indication of the long-term performance of plastic piping materials.

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[7] *Brittle-Like Cracking in Plastic Pipe For Gas Service*, NTSB Report No. NTSB/SIR-98/01, National Transportation Safety Board, Washington, D.C., April 1998.

[8] U.S. Department of Transportation statistics indicate approximately 539,000 miles of plastic main and 36.8 million plastic services were installed at the end of 2004.

Status of Voluntary Participation

Approximately 145 companies[9] have volunteered to participate in the Plastic Pipe Data Collection and Sharing Initiative. These companies operate 73% of the total mileage of installed plastic main in the U.S. and 78% of the total number of installed plastic services. The PPDC actively encourages additional voluntary participation to ensure the broadest coverage possible and to enhance the value of the database as a barometer of plastic material performance. AGA and APGA continue to encourage additional voluntary participation of their member companies. The NAPSR and NARUC discuss the PPDC at regional and national meetings and encourage operators within their states to participate in the PPDC.

Status of Data Collection

AGA began collecting data on January 25, 2001. Collected data include both actual failure information and negative reports (i.e. one-page forms completed by participating companies indicating that they had no failure data to submit during the month). This is the start of the sixth year of data collection and the data collected to date represents a full five-year leak survey cycle for the country's distribution systems.

Although the data is being reviewed by the PPDC, the data cannot be directly correlated to quantities of each material that may be in service across the U.S. Therefore, the PPDC is not able to assess the failure rates of these materials. However, it is the joint conclusion of the PPDC members that at this time, the failure data points reinforce what is already (and historically) known about certain older plastic piping and components. Some of these were identified in 2000 by a government-industry group[10] and have resulted in a DOT Advisory Bulletin[11]. The bulletin can be found on the OPS website at http://ops.dot.gov, under "What's New Previous Year Link 2002". The historically known information covers the following plastic pipe and components:

1. Polyethylene (PE) pipe manufactured by Century Utility Products
2. Pre-1973 DuPont Aldyl® A low ductile inner wall plastic pipe
3. PE pipe manufactured from PE 3306 resin
4. Delrin insert tap tees
5. Plexco service tee Celcon (polyacetal) cap

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[9] This number has dropped from approximately 160 companies in 1999 to approximately 150 companies in 2005 due to acquisitions and mergers.

[10] Robert J. Hall, *Brittle-Like Cracking of Plastic Pipe*, Final Report No. DTRS56-96-C-0002-006, General Physics Corp., Columbia, Maryland, August 2000.

[11] DOT Advisory Bulletin ADB-02-07, *Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe*, Federal Register, Volume 67, Number 228, p. 70806, November 26, 2002 and Federal Register, Volume 67, Number 232, p. 72027, December 3, 2002.

In an effort to assist the gas utilities, the Gas Piping Technology Committee (GPTC) has prepared new guidance material that an operator can use when these older plastic pipe materials are known to be present in their piping system. The new guidance material was published in May 2005, under Subpart L, Section 192.613, as part of Addendum No. 2 to the 2003 edition of the guide.

In addition, the AGA Plastic Materials Committee is updating the AGA Plastic Pipe Manual. This manual contains information on plastic pipeline materials, including factors affecting plastic piping performance, engineering consideration for plastic pipe utilization, procurement considerations and acceptance tests, installation guidance, personnel training, field inspection and pressure testing, operations and maintenance and emergency control procedures. The manual is now available through the AGA website, www.aga.org.

Finally, the PPDC is compiling a document that captures historical plastic material manufacturing information. Once complete, this document will identify the manufacturers of plastic pipe, joints and fittings for gas distribution operations, material designations, when the materials were produced, size ranges and other important information. For example, under plastic pipe, NIPAK pipe would show a material designation of PE 2306/2406, produced from 1970 to 1985, with size ranging from ½" CTS – 12" IPS, and NIPAK's PE 3306, produced in 1970, with a size range of ¾" IPS – 4" IPS. The comment field would note that the pipe was orange, that NIPAK was a subsidiary to Lone Star from 1970-1980, NIPAK was sold in 1980 to Arco Chemical and became a stand-alone company in 1982. The company went bankrupt in 1985. The PPDC expects to release the pipeline portion of this document first quarter 2007.

For the many miles of these older PE materials still in service in the U.S., the key unknown is the projected performance of these pipes. The rate process method (RPM) can be used to determine if there is an early transition to brittle-like properties of PE materials. The RPM can also be used to predict performance of PE materials at their in-ground temperatures and pressures based on both internal pressure as the primary load and secondary loads such as rock impingement and squeeze-off.[12]

AGA is available to help participants complete the failure report or negative report forms if there are any questions by a participant. The AGA website contains the latest versions of FAQs, data collection forms, form instruction, definitions, PPDC rosters, previous annual reports, a data collection PowerPoint tutorial entitled "Plastic Pipe Data Collection" and further details on the goals of the plastic pipe database initiative. From the AGA website, www.aga.org, select "Operations and Engineering" and then "Plastic Piping Data Project."

With this annual report, the PPDC continues to urge all natural gas distribution system operators to volunteer as an active participant in this proactive and worthwhile initiative.

For additional information about this initiative, contact Christina Sames at AGA (by telephone 202/824-7214 or electronically at csames@aga.org) or John Erickson at APGA (by telephone at 202/464-0834 or electronically at jerickson@apga.org).

[12] Bragaw, C.G., "Prediction of Service of Polyethylene Gas Piping System," *Proceedings Seventh Plastic Fuel Gas Pipe Symposium,* pp. 20-24, 1980, and Bragaw, C.G., "Service Rating of Polyethylene Piping Systems by the Rate Process Method," *Proceedings Eighth P*

APPENDIX D

Sec. 60109. High-density population areas and environmentally sensitive areas

(a) Identification Requirements. - Not later than October 24, 1994, the Secretary of Transportation shall prescribe standards that - (1) establish criteria for identifying -

(A) by operators of gas pipeline facilities, each gas pipeline facility (except a natural gas distribution line) located in a high-density population area; and

(B) by operators of hazardous liquid pipeline facilities and gathering lines -
(i) each hazardous liquid pipeline facility, whether otherwise subject to this chapter, that crosses waters where a substantial likelihood of commercial navigation exists or that is located in an area described in the criteria as a high density population area; and

(c) Risk Analysis and Integrity Management Programs. -
(1) Requirement. - Each operator of a gas pipeline facility shall conduct an analysis of the risks to each facility of the operator located in an area identified pursuant to subsection (a)(1) and defined in chapter 192 of title 49, Code of Federal Regulations, including any subsequent modifications, and shall adopt and implement a written integrity management program for such facility to reduce the risks.

(2) Regulations. -
(A) In general. - Not later than 12 months after the date of enactment of this subsection, the Secretary shall issue regulations prescribing standards to direct an operator's conduct of a risk analysis and adoption and implementation of an integrity management program under this subsection. The regulations shall require an operator to conduct a risk analysis and adopt an integrity management program within a time period prescribed by the Secretary, ending not later than 24 months after such date of enactment. Not later than 18 months after such date of enactment, each operator of a gas pipeline facility shall begin a baseline integrity assessment described in paragraph (3).

(B) Authority to issue regulations. - The Secretary may satisfy the requirements of this paragraph through the issuance of regulations under this paragraph or under other authority of law.
(3) Minimum requirements of integrity management programs. – An integrity management program required under paragraph (1) shall include, at a minimum, the following requirements:

(A) A baseline integrity assessment of each of the operator's facilities in areas identified pursuant to subsection (a)(1) and defined in chapter 192 of title 49, Code of Federal Regulations, including any subsequent modifications, by internal inspection device, pressure testing, direct assessment, or an alternative method that the

Secretary determines would provide an equal or greater level of safety. The operator shall complete such assessment not later than 10 years after the date of enactment of this subsection. At least 50 percent of such facilities shall be assessed not later than 5 years after such date of enactment. The operator shall prioritize such facilities for assessment based on all risk factors, including any previously discovered defects or anomalies and any history of leaks, repairs, or failures. The operator shall ensure that assessments of facilities with the highest risks are given priority for completion and that such assessments will be completed not later than 5 years after such date of enactment.

(e) **DISTRIBUTION INTEGRITY MANAGEMENT PROGRAMS.—**

(1) MINIMUM STANDARDS.—Not later than December 31, 2007, the Secretary shall prescribe minimum standards for integrity management programs for distribution pipelines.

(2) ADDITIONAL AUTHORITY OF SECRETARY.—In carrying out this subsection, the Secretary may require operators of distribution pipelines to continually identify and assess risks on their distribution lines, to remediate conditions that present a potential threat to line integrity, and to monitor program effectiveness.

(3) EXCESS FLOW VALVES.—
(A) IN GENERAL.—The minimum standards shall include a requirement for an operator of a natural gas distribution system to install an excess flow valve on each single family residence service line connected to such system if—
(i) the service line is installed or entirely replaced after June 1, 2008;
(ii) the service line operates continuously throughout the year at a pressure not less than 10 pounds per square inch gauge;
(iii) the service line is not connected to a gas stream with respect to which the operator has had prior experience with contaminants the presence of which could interfere with the operation of an excess flow valve;
(iv) the installation of an excess flow valve on the service line is not likely to cause loss of service to the residence or interfere with necessary operation or maintenance activities, such as purging liquids from the service line; and
(v) an excess flow valve meeting performance standards developed under section 60110(e) of title 49, United States Code, is commercially available to the operator, as determined by the Secretary.

(B) REPORTS.—Operators of natural gas distribution systems shall report annually to the Secretary on the number of excess flow valves installed on their systems under subparagraph (A).

(4) APPLICABILITY.—The Secretary shall determine which distribution pipelines will be subject to the minimum standards.

(5) DEVELOPMENT AND IMPLEMENTATION.— Each operator of a distribution pipeline that the Secretary determines is subject to the minimum standards prescribed by the Secretary under this subsection shall develop and implement an integrity management program in accordance with those standards.

(6) SAVINGS CLAUSE.—Subject to section 60104(c), a State authority having a current certification under section 60105 may adopt or continue in force additional integrity management requirements, including additional requirements for installation of excess flow valves, for gas distribution pipelines within the boundaries of that State.

(f) CERTIFICATION OF PIPELINE INTEGRITY MANAGEMENT PROGRAM PERFORMANCE.—The Secretary shall establish procedures requiring certification of annual and semiannual pipeline integrity management program performance reports by a senior executive officer of the company operating a pipeline subject to this chapter. The procedures shall require a signed statement, which may be effected electronically in accordance with the provisions of the Electronic Signatures in Global and National Commerce Act (15 U.S.C. 7001 et seq.), certifying that—
(1) the signing officer has reviewed the report; and
(2) to the best of such officer's knowledge and belief, the report is true and complete.

APPENDIX E

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Operations & Engineering

April 8, 2003

Dockets Facility
U.S. Department of Transportation
Room PL-401
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Washington, D.C. 20590-0001

Re: Docket No. RSPA-00-7666, Notice 4
Preliminary Comments to the Proposed Rule, Pipeline Integrity Management (Gas Transmission)

The American Gas Association (AGA) appreciates the opportunity to submit comments to the proposed rule for Pipeline Integrity Management in High Consequence Areas (Gas Transmission). This letter provides preliminary comments regarding integrity management of low stress gas transmission pipelines and the need for time interval parity of direct assessment as an effective method in the proposed rule.

Local distribution companies (LDC), whom AGA and the American Public Gas Association (APGA) represent, operate over 52,000 miles of intrastate transmission pipelines. AGA estimates that approximately 42%, or 21,800 miles, of these pipelines fall under the general concept of the High Consequence Area definition (i.e. class 3 and 4 locations plus some class 1 and 2 locations where identified sites exist within an impact circle). Based upon a survey of its members conducted in August 2002, AGA and APGA estimate that 11,100 miles of transmission pipe in high consequence areas (HCAs) will be assessed utilizing direct assessment.

Low stress pipelines as referred to herein, are those lines that operate at less than 30% of the Specified Minimum Yield Strength (SMYS). Approximately 45%, or 9,810 miles, of the utility transmission pipelines in HCAs operate below 30% SMYS. There is substantial literature in the docket that explains that time dependent threats to low stress pipelines fail differently (i.e. leak vs. rupture) than pipelines that operate between 30% and 80% of SMYS. Time dependent threats are the primary threats being addressed by RSPA's proposal to mandate the use of in-line inspection (ILI), pressure testing, and direct assessment (DA) on transmission pipelines in HCAs.

RSPA acknowledged that low stress pipelines pose less risk and require less stringent regulatory measures than higher stress pipelines. In the above referenced notice of proposed rulemaking RSPA stated,

> *"Pipelines that operate at a stress level less than 30% SMYS fail differently (i.e., leak rather than rupture) from those operating at higher stress. Therefore, different integrity assurance techniques may be appropriate. These low stress pipes have been shown both by fracture mechanics analysis and by evaluation of failure experience data to fail by leaking, not by rupture. Therefore, the techniques most effective in assuring the integrity of these pipelines could reasonably involve a combination of integrity assessment techniques and enhanced leak detection."*

RSPA also stated,

> *"Current gas pipeline safety regulations recognize the reduced risk that low stress levels pose, and structure the requirements accordingly. Examples of different requirements for pipelines operating at lower stress are in § 192.65 (Transportation of pipe), § 192.227 (Qualification of welders), § 192.241 (Inspection and test of welds), § 192.309 (Repair of steel pipe), § 192.315 (Wrinkle bend in steel pipe), § 192.319 (installation of pipe in a ditch, § 192.505 (Strength requirements for steel pipeline to operate at a hoop stress of 30% or more of SMYS), § 192.711 (General requirements for repair procedures), and § 192.717 (Permanent field repair of leaks)."*

AGA agrees with RSPA's above referenced assessments and has previously highlighted these issues in comments submitted to the docket (docket items RSPA-2000-7666-73 and RSPA-2000-7666-86). In these previous comments, AGA argued that pipelines operating below 20% SMYS should be not be covered under the impending integrity management regulation. While AGA still believes that this is technically justified, AGA recognizes that the Pipeline Safety Act of 2002 does not give RSPA the flexibility to exclude such pipelines from the regulation. AGA would like to pursue a future effort to better address integrity management requirements for transmission pipelines operating at or below 20% SMYS. In the meantime, AGA is including the transmission pipelines operating below 20% SMYS in our proposal for addressing integrity assessments under the category of pipelines operating below 30% SMYS.

AGA hopes that these additional comments will facilitate further public discussion of ways to develop appropriate regulations to enhance the integrity management of low stress pipelines. Our comments focus on the following areas:

- Direct Assessment Schedule Parity
- High Consequence Areas as Related to Low Stress Pipelines
- Assessment Requirements for Low Stress Pipelines in Class 3 and 4 Locations but Outside HCAs.
- Baseline and Reassessment Requirements for Low Stress pipelines inside HCAs.

<u>Direct Assessment Schedule Parity</u>

Providing the same assessment schedule for direct assessment (DA) as that given for in-line inspection and pressure testing, is an essential element in providing flexibility for low stress pipelines in the integrity management rule.

AGA and APGA members need to utilize DA because in-line inspection and pressure testing are not universally feasible in a sense that retrofitting many pipelines to accommodate ILI tools would be very costly (from $1.3 to $ 3.8 billion over 20 years in some cases approaching total replacement costs), or that service interruptions would be quite likely.

LDC transmission pipelines are intrastate lines, and in general, more difficult to retrofit as compared to interstate transmission pipelines because they are typically integrated with the distribution systems they supply. Interstate pipelines are typically designed to traverse long distances (over hundreds of miles), primarily in rural areas. On the other hand, LDC transmission pipelines are typically designed to traverse shorter distances (tens of miles), primarily in urban environments featuring more densely populated areas as reflected by pipe location classes 3 and 4. This is apparent in the 2001 RSPA transmission annual reports. Based upon the report database, the Interstate Natural Gas Association of America (INGAA) estimates that interstate pipelines (INGAA members) operate only around 10,000 miles (out of approximately 160,000 miles) of class 3 and 4 pipe. AGA and APGA members on the other hand, operate around 16,000 miles (out of approximately 52,000 miles) of class 3 and 4 pipe.

The intent of RSPA's integrity management regulation is to focus resources on the pipelines in the highest consequence areas. However, AGA believes that mandating a baseline assessment of low stress pipelines within 7 years (within 4 years for the riskiest 50%), instead of 10 years (and 5 years for the riskiest 50%) as provided for ILI and pressure testing, goes against RSPA's intent as well as the intent of Congress, and unnecessarily adds to the costs of compliance with the rule. AGA estimates this will add over $740 million to the cost of compliance over 10 years. This is further exacerbated by the fact that the rule's implementation is not expected to begin until at least a year from enactment of the law, in effect shortening the baseline interval by an additional year.

The purpose of the Congressional baseline assessment schedule in the Pipeline Safety Improvement Act of 2002 (PL 107-355, December 17, 2002), was to provide adequate time in which to complete one assessment of the entire pipeline system in HCAs within 10 years, regardless of the method used. AGA does not understand the technical basis for accelerating assessments that use the DA method. Presumably RSPA is concerned that DA cannot effectively measure time dependent anomalies. If a threat can exist for a given time interval before examination by ILI, the same threat can exist for the same time interval before being examined by direct assessment.

In the legislation, Congress gave instruction directly to operators, leaving no room for Secretary of Transportation discretion on when to complete baseline assessments and on how often to conduct reassessments. Congress did direct the Secretary to prescribe standards for the integrity management program. However, the standards must not contradict the time schedule established by Congress. When the Pipeline Safety Act of 2002 spoke of minimum requirements, it wanted RSPA to prescribe a regulation that included sufficient time for effective implementation of each requirement as described in Section 60109 (c)(3), paragraphs (A) through (H) of the Act. Congress did not want RSPA to change Congressional directives. This argument has a precedent in case law, such as in *Chevron U. S. A. Inc. v. Natural Resources Defense Council, Inc.*, 467 U.S. 837, 842 (1984) and in *Christine Todd Whitman, Administrator of The Environmental protection Agency, et al. v. American Trucking Association*, 531 U.S. 457, (2001).

To ensure sufficient time is available for affordable assessment of utility pipelines, particularly low stress pipelines, AGA recommends that the baseline and reassessment intervals for DA be made the same as for ILI and pressure testing. If, in the future, field experience indicates changes to be needed, the rule could be amended by RSPA.

To help address RSPA's concern regarding the ability of DA to identify time dependent defects, AGA as well as INGAA, have invited RSPA's staff and members from the National Association of Pipeline Safety Representatives (NAPSR), to participate in all of the research taking place on direct assessment this year. Specifically for LDCs, AGA has teamed up with the Gas Technology Institute (GTI) to pursue an external corrosion direct assessment (ECDA) research effort. The map reflected in attachment 1, lists the participating companies and the states that they operate in. A minimum of 6, with a possibility of up to 15, case studies will be pursued under this research effort.

RSPA and NAPSR representatives are welcome to review detailed protocols for each of the four steps involved in the ECDA process (i.e. pre-assessment, indirect examination, direct examination, post assessment). In addition, representatives are invited to witness indirect and direct examination field activities.

Other direct assessment related efforts include the following:

1. PRCI/GTI ECDA, ICDA, and SCC DA research.
2. Northeast Gas Association (NGA) ECDA research.
3. NACE ICDA and SCC DA standards development.

AGA understands that RSPA is co-funding some ECDA research in conjunction with GTI and PRCI under one of RSPA's Broad Agency Announcement on pipeline safety research.

AGA is confident that through RSPA's involvement in all of these research efforts, RSPA will gain the confidence to provide the same assessment schedules for DA as those given for ILI and pressure testing. By doing so, flexibility will be provided for LDC transmission pipelines, particularly those operating at low stress levels, thus allowing operators to appropriately allocate resources on higher risk pipelines first.

High Consequence Areas

During the OPS public meeting on March 14, 2003 and the TPSSC meeting on March 27, 2003, INGAA and AGA proposed a bifurcated approach to the added layer of protection provided by the HCA definition. This basically would allow an operator to either use an impact circle with the threshold number of 20 buildings or an identified site to delineate an HCA along a pipeline, or to use a combination of Class 3 and 4 locations and the impact circle approach for identified sites in Class 1 and 2 locations to delineate an HCA.

While considering this approach at the TPSSC meeting, RSPA expressed concern that if low stress pipelines apply the impact circle approach without an added safety margin (i.e. the "threshold radius" in the proposed rule), few if any, low stress pipelines in class 3 and 4 locations would be considered HCAs. This is because the smaller diameter and lower pressure characteristics of typical low stress pipelines result in small impact circles without the requisite threshold number of buildings to produce an HCA. Since AGA has not conducted specific surveys among its membership as to the accuracy of this concern, it is not possible at this time to predict how many low stress pipelines in class 3 and 4 locations will be considered to be outside HCAs if the impact circle approach is utilized, or how many clusters of 20 or more buildings within the circle in class 2 locations will be picked up as HCAs.

The formula utilized for calculating the potential impact circle was developed with an assumption of a pipeline failure resulting in a rupture. Studies have shown that for time dependent threats, low stress pipelines leak rather than rupture, when they are operating below 30% SMYS. Therefore, the potential impact circle formula conservatively calculates an impact circle for pipelines operating below 30% SMYS. With this technical basis, AGA believes that areas that do not meet the thresholds for the impact circle are not HCAs, which is consistent with the industry HCA proposal.

AGA nonetheless, recognizes that, pursuant to the Pipeline Safety Improvement Act of 2002, all gas transmission pipelines in high-density population areas (i.e. HCAs) must have an added layer of protection (beyond that already afforded by existing requirements in 49 CFR part 192 for class 3 and 4 locations) through an integrity management program. RSPA has stated that to meet this legislative intent and to address the potential consequences of leaks, they propose to require added protection for low stress pipelines in class 3 and 4 locations even if those pipelines that do not meet the HCA criteria using potential impact circles.

Assessment Requirements for Low Stress Pipelines in Class 3 and 4 Locations but Outside HCAs

AGA proposes such added protection be assessments in the form of preventive and mitigative measures aimed at addressing the threats associated with pipeline leaks with the highest probability of occurrence, namely leaks due to third party damage and leaks due to corrosion. Preventive and mitigative measures meet the Pipeline Safety Improvement Act of 2002 assessment method category of "an alternative method that the Secretary determines would provide an equal or greater level of safety."

Table A below reflects an AGA proposal for such added protection. It is important to note that these added requirements would apply only to low stress transmission pipelines that are not in HCAs, but are in class 3 and 4 locations. It is also important to note that a baseline assessment as referred to in the propose rule, is not required for these pipelines. The added measures of protection are shown in column 4 of the table. They take into account the fact that for leak detection and for adequate responses to leaks, it is essential that the gas be odorized per requirements of 49 CFR Section 192.625 Odorization of gas. Odorization in itself adds a layer of protection in that it provides a mechanism for the public to detect and report leaks.

Table A shows that for cathodically protected low stress transmission pipeline segments, the added assessments double the number of required leak surveys conducted on a periodic basis. Similarly, for unprotected transmission pipelines, or for cathodically protected pipe where electrical surveys are impractical, the proposed assessment schedule is tightened by a leak survey frequency four times the frequency required by the existing regulations. Furthermore, added actions by the operator in the area of excavation damage prevention are formalized in column 4.

Table A
Proposed Assessment Methods for addressing Time Dependent and Independent Threats, for Transmission Pipelines Operating Below 30% SMYS not in HCAs but in Class 3 and 4 Locations

(Column 1) Threat	Existing 192 Requirements (Column 2) Primary	(Column 3) Secondary	(Column 4) Additional (to 192 requirements) Assessments
External Corrosion	455-(Gen. Post 1971), 457-(Gen. Pre-1971) 459-(Examination), 461-(Ext. coating) 463-(CP), 465-(Monitoring) 467-(Elect isolation), 469-Test stations) 471-(Test leads), 473-(Interference) 479-(Atmospheric), 481-(Atmospheric) 485-(Remedial), 705-(Patrol) 706-(Leak survey), 711 (Repair – gen.) 717-(Repair – perm.)	603-(Gen Oper) 613-(Surveil)	*For Cathodically Protected Trmn. Pipeline* • Perform semi-annual leak surveys. *For Unprotected Trmn. Pipelines or for Cathodically Protected Pipe where Electrical Surveys are Impractical* • Perform quarterly leak surveys
Internal Corrosion	475-(Gen IC), 477-(IC monitoring) 485-(Remedial), 705-(Patrol) 706-(Leak survey), 711 (Repair – gen.) 717-(Repair – perm.)	53(a)-(Materials) 603-(Gen Oper) 613-(Surveil)	• Perform semi-annual leak surveys.
3rd Party Damage	103-(Gen. Design), 111-(Design factor) 317-(Hazard prot), 327-(Cover) 614-(Dam. Prevent), 616-(Public educat) 705-(Patrol), 707-(Line markers) 711 (Repair – gen.), 717-(Repair – perm.)	615 –(Emerg Plan)	• Participation in state one-call system, • Qualification of excavators working under operator's control, AND • Upon notification of excavation activity, on-site observation of construction activities around transmission pipelines except in cases in which the operator is assured no potential damage to the pipeline exists. If the operator expects that any portion of the pipeline will be exposed, personnel will be on site to observe such activities. Note clarification will be necessary to determine what constitutes appropriate notification. OR • Monthly patrolling of transmission pipelines in HCAs. Any indications of unreported construction activity would require a follow up investigation to determine if mechanical damage occurred.

Baseline and Re-Assessment Requirements for Low Stress Pipelines Inside HCAs

AGA supports the position that all transmission pipelines in high consequence areas must be baseline assessed utilizing ILI, pressure testing, direct assessment, or other effective technology. AGA believes that the table 8-1 of the ASME B31.8S standard (as referenced in the NPRM), appropriately addresses the re-assessment requirements for low stress pipelines when addressing time dependent threats.

AGA proposes that RSPA incorporate the maximum intervals set for pipelines operating below 30% SMYS in the standard. In addition, AGA proposes that ongoing preventive and mitigative assessment measures be applied to meet the legislative mandate of a re-assessment every 7 years. As previously discussed, preventative and mitigative measures meet the Pipeline Safety Act of 2002 assessment method category of "an alternative method that the Secretary determines would provide an equal or greater level of Safety."

AGA's proposals for baseline and re-assessment for low stress pipelines within HCAs are reflected in tables B and C below. Table B includes the assessment requirements for high stress pipelines (as proposed in the NPRM) for comparison. It should be noted that the re-assessment intervals represented in table B reflect a parity between ILI, pressure testing, and DA.

AGA members have indicated that for the next 3 to 5 years under an integrity management rule, they will most likely consider all class 3 and 4 locations as HCAs. This is mostly because LDCs consider many of their pipelines to be in class 3 and 4 locations regardless of whether or not they meet the detailed building counts in the definitions of 49 CFR Section 192.5. This is considered to be less burdensome and more efficient rather than conducting class location surveys on an annual basis. As mapping systems are enhanced and as population data is collected along pipeline right-of-ways, LDCs will most likely pursue the impact circle approach to the HCA definition. Therefore, the requirements in table B and C would apply to the majority of low stress pipelines in class 3 and 4 locations operated by LDCs in the near term.

Table B
Assessment Requirements for Transmission Pipelines in HCAs (Re-assessment intervals are maximum allowed)

	Re-Assessment Requirements (see Note 3)					
	At or above 50% SMYS		At or above 30% SMYS up to 50% SMYS		Below 30% SMYS	
Baseline Assessment Method (see Note 3)	Max Re-Assessment Interval	Assessment Method	Max Re-Assessment Interval	Assessment Method	Max Re-Assessment Interval	Assessment Method
Pressure Testing	7	CDA	7	CDA	Ongoing	Preventative & Mitigative (P&M) Measures (see Table C), (see Note 2)
	10	Pressure Test or ILI or DA				
		Repeat inspection cycle every 10 years	14	Pressure Test or ILI or DA (see Note 1)		
				Repeat inspection cycle every 14 years	20	Pressure Test or ILI or DA
						Repeat inspection cycle every 20 years
In-Line Inspection	7	CDA	7	CDA	Ongoing	Preventative & Mitigative (P&M) Measures (see Table C), (see Note 2)
	10	ILI or DA or Pressure Test				
		Repeat inspection cycle every 10 years	14	ILI or DA or Pressure Test (see Note 1)		
				Repeat inspection cycle every 14 years	20	ILI or DA or Pressure Test
						Repeat inspection cycle every 20 years
Direct Assessment	7	CDA	7	CDA	Ongoing	Preventative & Mitigative (P&M) Measures (see Table C), (see Note 2))
	10	DA or ILI or Pressure Test				
		Repeat inspection cycle every 10 years	14	DA or ILI or Pressure Test (see Note 1)		
				Repeat inspection cycle every 14 years	20	DA or ILI or Pressure Test
						Repeat inspection cycle every 20 years

Note 1: Operator may choose to utilize CDA at year 14, then utilize ILI, Pressure Test, or DA at year 15 as allowed under ASME B31.8S

Note 2: Operator may choose to utilize CDA at year 7 and 14 in lieu of P&M

Note 3: Operator may utilize “other technology that an operator demonstrates can provide an equivalent understanding of the condition of line pipe”

Table C
Preventative & Mitigative Measures addressing Time Dependent and Independent Threats for Transmission Pipelines that Operate Below 30% SMYS , in HCAs

Threat	Existing 192 Requirements		Additional (to 192 requirements) Preventative & Mitigative Measures
	Primary	Secondary	
External Corrosion	455-(Gen. Post 1971) 457-(Gen. Pre-1971) 459-(Examination) 461-(Ext. coating) 463-(CP) 465-(Monitoring) 467-(Elect isolation) 469-Test stations) 471-(Test leads) 473-(Interference) 479-(Atmospheric) 481-(Atmospheric) 485-(Remedial) 705-(Patrol) 706-(Leak survey) 711 (Repair – gen.) 717-(Repair – perm.)	603-(Gen Oper) 613-(Surveil)	For Cathodically Protected Trmn. Pipelines • Perform an electrical survey (i.e. indirect examination tool/method) every 7 years. Results are to be utilized as part of an overall evaluation of the CP system and corrosion threat for the covered segment. Evaluation shall include consideration of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment. For Unprotected Trmn. Pipelines or for Cathodically Protected Pipe where Electrical Surveys are Impracticable • Conduct quarterly leak survey s. AND • Every 1-1/2 years, determine areas of active corrosion by evaluation of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.
Internal Corrosion	475-(Gen IC) 477-(IC monitoring) 485-(Remedial) 705-(Patrol) 706-(Leak survey) 711 (Repair – gen.) 717-(Repair – perm.)	53(a)-(Materials) 603-(Gen Oper) 613-(Surveil)	• Obtain and review gas analysis data each calendar year for corrosive agents from transmission pipelines in HCAs. • Periodic testing of fluid removed from pipelines. Specifically, once each calendar year from each storage field that may affect transmission pipelines in HCAs. • Every 7 years, integrate data obtained with applicable internal corrosion leak records, incident reports, safety related condition reports, repair records, patrol records, exposed pipe reports, and test records.
3rd Party Damage	103-(Gen. Design) 111-(Design factor) 317-(Hazard prot) 327-(Cover) 614-(Dam. Prevent) 616-(Public educat) 705-(Patrol) 707-(Line markers) 711 (Repair – gen.) 717-(Repair – perm.)	615 –(Emerg Plan)	• Participation in state one-call system, • Qualification of excavators working under operator's control, AND • Upon notification of excavation activity, on-site observation of construction activities around transmission pipelines except in cases in which the operator is assured no potential damage to the pipeline exists. If the operator expects that any portion of the pipeline will be exposed, personnel will be on site to observe such activities. Note clarification will be necessary to determine what constitutes appropriate notification. OR • Monthly patrolling of transmission pipelines in HCAs. Any indications of unreported construction activity would require a follow up investigation to determine if mechanical damage occurred.

Conclusion

AGA agrees with RSPA's assessment that low stress pipelines (operating below 30% SMYS) fail differently (i.e. leak vs. rupture) and therefore pose reduced risks in regards to pipeline safety. In order to address RSPA's intent on focusing on pipelines of "high consequence", assessment flexibility for low stress pipelines needs to be incorporated in the natural gas integrity management regulation. This can be addressed by the following:

- Provide direct assessment schedule parity with ILI and pressure testing.
- Allow added protection for low stress pipelines in the form of preventive and mitigative measures in class 3 and 4 locations that are outside HCAs.
- Allow the use of preventive and mitigative measures as alternate assessment methods for re-assessments of low stress pipelines inside HCAs.

AGA's proposals outlined in tables A through C, appropriately address the legislative integrity assessment mandates and add an enhanced level of protection to pipelines that already have a significantly low probability of incidents. AGA intends to discuss this proposal at the next OPS public meeting scheduled for April 25 in Dulles, VA.

Respectfully submitted,

AMERICAN GAS ASSOCIATION

Lori Traweek

By: ________________________________
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Attachment